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STAFF REPORT

2012 NATURAL GAS MARKET TRENDS

In Support of the *2012 Integrated Energy Policy Report Update*

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PREFACE

State government has an essential role to ensure that a reliable supply of energy is provided consistent with protection of public health and safety, promotion of the general welfare, maintenance of a sound economy, conservation of resources, and preservation of environmental quality (Public Resources Code [PRC] Section 25300[b]). To perform this role, state government needs a complete understanding of the operation of energy markets, including electricity, natural gas, petroleum, and alternative energy sources, to enable it to respond to possible shortages, price shocks, oversupplies, or other disruptions (PRC Section 25300[c]). The California Energy Commission's timely reporting, assessment, forecasting, and data collection are essential to serve the information and policy development needs of the Governor, the Legislature, public agencies, market participants, and the public (PRC Section 25300[c]).

This staff report provides an overview of major natural gas market trends and issues facing the state, including, but not limited to, supply, demand, pricing, reliability, efficiency, and impacts on public health and safety, the economy, resources, and the environment (PRC25302[a]).

ABSTRACT

The *2012 Natural Gas Market Assessment: Trends* is produced as part of the California Energy Commission's *2012 Integrated Energy Policy Report Update*. This report reviews recent trends in natural gas supplies, demand, prices, and infrastructure. This review of trends helped staff identify key drivers of future natural gas market activities, which were explored in the companion report, *2011 Natural Gas Market Assessment: Outlook*.

Keywords: Natural gas, shale, hydraulic fracturing, fracking, supply, demand, infrastructure, trading hub, border price, citygate, price, production, processing, pipelines, liquefied natural gas, LNG, regasification, maximum allowed operating pressure.

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EXECUTIVE SUMMARY

Over the last five years, the natural gas industry has experienced a dramatic shift as natural gas produced from shale formations has emerged as a major new source of supplies. In 2007, California faced key challenges as more than 85 percent of its natural gas came from conventional out-of-state supplies that appeared to be dwindling and whose production costs were increasing. The question then was how could California, located at the end of the interstate pipeline system, secure adequate and reliable natural gas supplies at reasonable prices. At that point, there were as many as four proposals for liquefied natural gas (LNG) facilities in the state to supplement supplies through imported natural gas from other countries. In the ensuing years, the majority of LNG proposals were abandoned, while domestic shale gas grew from 5 percent of total United States natural gas production to more than 30 percent. Today, natural gas supplies in the United States are abundant, prices are low, and the United States faces the prospect of becoming an exporter of LNG as producers seek higher prices for their natural gas on the world market.

Concurrent with this changing supply picture, which has produced dramatically lower natural gas prices than at their 2008 peak, new issues are emerging around the pipeline and storage infrastructure that deliver natural gas to consumers. Among these is the rerouting of natural gas flows on newly constructed pipelines as the new shale gas supplies are often not located in North America's most prolific supply basins, which already have extensive infrastructure. In addition, the increasing competition between natural gas supply basins and demand regions is changing the direction of natural gas flows on pipeline infrastructure across the country. Higher delivery costs are likely going forward due to the vitally necessary emphasis on pipeline safety following the 2010 San Bruno natural gas pipeline explosion. New environmental regulations that also affect pipeline facility costs may also add to these higher delivery costs.

Emergence of Shale Gas as a Major Natural Gas Supply

Natural gas production in the Lower 48 United States has increased from 50 billion cubic feet per day in 2005 to 63 billion cubic feet per day in 2011, as production has shifted from conventional sandstone basins to shale and tight sandstone formations. This 20 percent increase in natural gas production is largely attributed to breakthroughs in hydraulic fracturing and horizontal drilling techniques that allow access to shale gas supplies and expand per-well recovery. In addition, the presence of crude oil and natural gas liquids (such as propane, ethane, and butane), commonly referred to as *wet gas*, is boosting the economic feasibility of shale plays or the geologic formation where natural gas is being (or can be) produced. Shale development is pushing overall natural gas resources to higher levels. In 2011, the United States had 2,543 trillion cubic feet of technically recoverable resources (proved and potential) from all natural gas formations, 827 trillion cubic feet of which was from shale formations.

Shale gas development is not without its challenges and controversies. The technology to extract natural gas from shale formations — known as *hydraulic fracturing* or f*racking* – involves injecting fluids at high pressure to break up the rock and hold the new fractures open to allow release of the natural gas. The fluids are primarily water, plus sand (either natural or synthetic) and a variety of different chemicals. The exact chemical mix differs by formation and by operator. The process uses large amounts of water, and while the industry insists the process is safe, chemicals can contaminate surface and groundwater if they escape. In addition, seismic activity has occurred, sometimes in locations where seismic activity was unknown prior to fracking activity. Scientists argue that either the fracturing pressures or the disposal injection post-fracking may be the cause, and several studies are underway.

Public health and environmental concerns have heightened as shale gas drilling and production take place near populated areas and/or in areas that previously have not experienced oil and natural gas production. The general areas of environmental concerns include surface disturbances, greenhouse gas (GHG) emissions, water use and disposal, and, as mentioned above, potential groundwater contamination. These concerns have led to the creation of a panel to advise Energy Secretary Steven Chu about best practices the federal government should encourage the industry to adopt. In addition, on May 4, 2012 Interior Secretary Ken Salazar released proposed rules for fracturing undertaken on federal and Indian lands. Uncertainty about whether and how these concerns are addressed will impact the amount and rate, as well as prices, of shale gas production going forward.

Declining Natural Gas Prices

Since the beginning of the year, natural gas prices have been very low, with the average Henry Hub spot price — the pricing point for natural gas futures contracts — from January 2012, through the end of April 2012 at $2.33 per million British thermal units and an average price for April 2012 of $1.94 per million British thermal units. Natural gas prices were increasing steadily up to 2008, when they began to drop. The monthly Henry Hub spot price increased by an average of 29 percent per year between 2000 and 2008. However, from January 2009 to April 2012, Henry Hub spot prices decreased at an average annual rate of 19 percent. Over the last decade, spot prices have been volatile, with several spikes resulting in prices as high as $13.80 per million British thermal units in June 2008. In recent months, there has been a dramatic decrease in natural gas prices with the March 2012 New York Mercantile Exchange futures contract expiring at a close price of $2.446 per million British thermal units. Current prices are a result of a warm winter and high production rates, creating an overhang of supply, as evidenced by an unprecedented 2.1 trillion cubic feet of natural gas in storage on March 1, 2012.

In the short term, it is unclear how shale gas producers will respond to the current very low prices of natural gas. It appears that some producers are backing off on production, but whether they can take actions quickly enough to stop the fall in prices or potentially raise prices is not apparent. Data for drilling rig counts show the number of natural gas rigs has dropped from roughly 900 on January 2011 to under 700 by March 2012. While low prices can discourage drilling in the shorter term, this could be only a temporary situation that may have little effect on shale gas production rates going forward.

An uncertainty related to shale gas development in the long term is whether and to what extent the United States becomes an LNG exporter and the implications this has for domestic prices of natural gas. United States law requires that export be demonstrated to be in the "national interest" before the United States Department of Energy (U.S. DOE) can grant an export permit. There are varying opinions about whether exporting LNG is in the national interest, and the U.S. DOE has commissioned two key studies. Domestic producers argue that they deserve the opportunity to compete for the higher natural gas prices available in the world market, where natural gas prices are often indexed to oil prices. Others argue that exporting LNG would expose the United States to world LNG and oil price fluctuations and would drive up the domestic price of natural gas.

Relatively Flat Natural Gas Demand Growth

Although United States supplies have increased, demand for natural gas nationally has remained relatively flat. The one exception is natural gas use for electricity generation, which is the main driver of United States natural gas demand growth. Over the next few years, federal air quality regulations will require major investments in existing coal facilities, many of which are reaching the end of their design life, to substantially reduce emissions. With low natural gas prices, coal facilities are less competitive, and rather than incur the financial investments necessary to keep these plants running, operators may simply choose to shut them down. This will result in increased United States demand for natural gas for electric generation.

Over the last 10 years, overall natural gas demand in the state, as well as residential sector demand, has remained relatively constant. California natural gas demand for the commercial sector increased, while industrial sector demand decreased. Growing natural gas demand for the transportation sector is an emerging issue in California as the state moves forward with policies to advance alternative and renewable fuels. Over the last decade, natural gas-fired generation has been a dominant source of electricity in California, accounting for as much as 59 percent of supplies in 2008. Natural gas demand for electric generation varies from year to year, depending on a number of factors including the availability of hydroelectric resources and weather.

California is implementing its Renewables Portfolio Standard, which will increase the amount of the renewable generation in the state to 33 percent by 2020. GHG reduction policies in California are reducing the state's long-term reliance on imports of coal generation from the Southwest. Some, or all, of these imports will be made up by the addition of renewable resources, including solar, wind, biomass, and geothermal. Natural gas demand for electric generation could increase substantially as renewable resources are developed and natural gas is used to integrate intermittent solar and wind generation into the California electricity grid. The amount of natural gas generation needed to integrate renewables going forward is uncertain as California is also pursuing investments in demand response and storage as a means of integrating renewable resources. Demand response entails end-use customers reducing their demand when prices change or when electricity system reliability is threatened. Energy storage allows electricity to be stored and called upon when needed to provide flexible and controllable services that help to neutralize the impact or intermittent generators. However, due to their unique operating characteristics, natural gas power plants are likely to be an important source of back-up generation for intermittent renewable resources.

Changing Flows and Increased Costs of Natural Gas Infrastructure

The location of shale production relative to traditional producing basins means that new pipelines and processing facilities have to be built to connect certain of these new supplies to market. It also means that some pipelines will reverse their flows. The Rockies Express pipeline, for example, built to move Rocky Mountain natural gas supplies to the Midwest and East, will begin to move Marcellus Shale gas production in the eastern United States westward.

At the same time, increasing competition in the natural gas market will influence the use of existing natural gas pipeline infrastructure. For example, the opening of the Ruby Pipeline last year provides another outlet for Wyoming natural gas besides the Kern River Pipeline, the Wyoming and Colorado Interstate Pipelines, Northwest Pipeline, and the newly constructed Rockies Express Pipeline. The Ruby Pipeline, which runs from Opal, Wyoming, to Malin, Oregon, gives Rocky Mountain natural gas a direct route to Northern California and displaces potentially declining Canadian supplies that would otherwise flow into California at Malin on TransCanada's Gas Transmission Northwest Pipeline.

While pipelines are expanding in some areas of the country, other pipeline owners, such as El Paso Natural Gas Company, are having trouble keeping capacity from more traditional supply basins fully subscribed. Without new subscribers for that existing capacity, they are attempting to abandon existing pipeline capacity. While a logical short-term response to cutting costs, with growing demand for natural gas for electric generation in California and the Southwest, it is unclear whether such abandonment will cause supply constraints in the longer term. In addition, Trans-Canada recently announced that its Gas Transmission Northwest Pipeline, which has been experiencing declining deliveries since the Ruby Pipeline came on-line in 2011, will now be operated as a bidirectional line, allowing it greater flexibility to serve the Northwest market.

The United States Environmental Protection Agency (U.S. EPA) has undertaken two efforts that can affect natural gas infrastructure: emissions reporting requirements for small natural gas production and distribution facilities, and polychlorinated biphenyls rules for natural gas pipelines. Small natural gas production and distribution facilities must report emissions of carbon dioxide, methane, and nitrous oxide as a result of new U.S. EPA rules implemented in 2011. Emissions from equipment leaks and venting, natural gas flaring, and stationary and portable production and distribution equipment that meet a threshold emissions level of 25,000 metric tons or more of carbon dioxide equivalent are covered by the rule. The new reporting requirements were prompted by a U.S. EPA study indicating that these emissions were previously underestimated by half and may ultimately result in additional regulations for the smaller facilities.

The U.S. EPA is considering changes to use authorizations for polychlorinated biphenyls, which were used as a lubricant in compressors in some natural gas pipelines and remain on-site. The U.S. EPA is considering sampling of polychlorinated biphenyls in pipelines to determine contamination of one part per million and requiring phaseout or termination of use authorizations to achieve remediation. The U.S. EPA has now settled on a final rule, the costs of which are not yet clear. However, the natural gas industry asserts that compliance costs could be very large and would significantly increase transportation costs.

As a result of the investigation into the San Bruno pipeline explosion, new rules are being developed to direct testing or replacement of pipelines for which the natural gas utilities have too little documentation of maximum allowable operating pressures, particularly for pipelines in urban areas where pipeline failure can have a high potential impact on people and property and those built before 1970. In addition, natural gas distribution utilities have filed Pipeline Safety Enhancement Plans, which detail testing and replacement efforts and estimate costs. Pacific Gas and Electric Co. (PG&E) estimates a Phase I cost of $2 billion before including financing costs. Southern California Gas Company (SoCal Gas) estimates Phase I of its pipeline Safety Enhancement Plans will cost $2.5 billion. Some of the costs include allowing use of in-line inspection tools as well as installing more remote-controlled and automatic valves. Also, efforts will be made to upgrade control and data acquisition systems that notify and interact with first responders. Some of the new rules for establishing minimum allowable operating pressures on older pipelines are also being considered by the Federal Pipeline and Hazardous Materials Safety Administration and could be applied elsewhere in the United States.

Changes to financial regulation passed by Congress in the aftermath of the 2008 financial crisis also have implications for the energy industry, including natural gas products, such as Henry Hub natural gas. The Commodity Futures Trading Commission has new rules that impose position limits, are designed to prevent speculation, and require more reporting of open positions, which could cause higher costs to purchase swaps and options and higher compliance costs. The impacts may also include higher collateral requirements and fewer market makers. There is at least some concern within the natural gas industry that the requirements could make hedging too expensive for energy commodity end users, depending on the final implementing regulations from the Commodities Futures Trading Commission.

Finally, a key issue growing in prominence is the need to harmonize natural gas and electricity markets and operations. Several recent studies, including the National Petroleum Council's 2011 report, highlighted this issue. The February 2011 rolling outages and natural gas curtailments in Texas, New Mexico, and Arizona that affected natural gas service to gas-fired generation in the San Diego Gas &Electric Company (SDG&E) service territory showed how important it is to ensure coordination of these markets. Differences in the timing and methodology with which the electricity and natural gas industries approach nominations and scheduling will become more apparent as natural gas generation displaces coal-fired generation. In addition, for natural gas generators to integrate intermittent renewable resources they will need to rely on natural gas supplies, which move more slowly through the pipeline infrastructure system, to more quickly respond to changing electricity system conditions. The North American Energy Standards Board has formed a committee to look at whether it can or should develop new standards, and Federal Energy Regulatory Commission (FERC) Commissioner Philip D. Moeller has asked for comments in advance of what may be a potential Notice of Proposed Rulemaking.

CHAPTER 1: Introduction

The natural gas market in California, the United States, and the world is undergoing a major transformation. A few years ago, the state was involved in a heated debate regarding the importation of liquefied natural gas (LNG) to complement domestic supplies. At one point, there were up to four proposals to build regasification facilities in the state to process natural gas from other countries.[1] Most of them have since withdrawn their applications. The current outlook for North American development of LNG regasification facilities in the near future does not look promising.

On the other hand, shale gas production is booming in the United States. Ten years ago, shale gas represented an insignificant portion of the total natural gas production in the United States, and most of the concern until 2008 focused on the rapid decline and increasing price of conventional natural gas resources. Now, natural gas appears abundant and prices are low, and new issues have arisen regarding pipeline and storage infrastructure, which will affect the price of natural gas in the future.

Chapter 2 describes the availability of shale gas resources, technology innovations, their costs, and the potential impacts of the hydraulic fracturing technology on the environment and public health.

Chapter 3 highlights historical and emerging trends in natural gas prices. It provides a description of the natural gas pricing mechanism. The interaction of supply and demand conditions is a key factor in determining prices, and at times speculation can play a significant role in the market. This chapter analyzes some of the pricing points, historical prices, and financial instruments used to trade natural gas in the market.

In Chapter 4, staff provides a historical perspective of natural gas demand by the residential, commercial, industrial, and electric generation sectors in the United States and California. In addition, the chapter also addresses some of the key drivers that have changed the demand in those sectors and will drive further changes going forward.

In Chapter 5, staff describes the current state of the natural gas infrastructure in the state, including pipelines, storage, and LNG facilities. It addresses major issues affecting infrastructure including recent natural gas curtailments in the Southwest and the need for natural gas-electricity industry harmonization, and new environmental regulations.

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1 The process of regasification involves receiving LNG, converting it to natural gas by use of vaporizers, and feeding the natural gas into the existing pipeline system. The process of liquefaction involves cooling natural gas (-260°F) to its liquid form, to be used in an LNG vehicle or exported on an LNG tanker.

CHAPTER 2: Natural Gas Supply Trends

California receives the majority of its natural gas supply from the Southwest, the Rocky Mountains, and Canada, making up roughly 85 percent of total supplies; the remaining 15 percent is produced in the state. In the last five years, the natural gas industry has transformed from one in which prices were relatively high and imported LNG supplies were needed to meet demand, to one in which prices are low, supply appears to be plentiful, and LNG import terminals are proposing to export rather than import natural gas. This transformation is largely a result of technological breakthroughs that have pushed natural gas production higher and costs lower. Shale gas resources have emerged as a major new supply source, adding substantially to the nation's natural gas reserves. Other important components in natural gas – including liquids such as ethane, propane, butane, and pentane – have increased in value and are driving the industry to invest in shale and sandstone formations with high liquid contents.

There are concerns about the hydraulic fracturing technique used to produce natural gas from shale and tight rock formations, including whether there is a potential for fracturing liquids to reach underground aquifers or other groundwater supplies.[2] Other concerns include surface disturbance, greenhouse gas emissions (GHG), water use and disposal, and the potential for increased seismicity.

This chapter explores current supply trends in natural gas production and reserves in the Lower 48 United States (Lower 48) and elsewhere; technology development; changing industry economics; and environmental and public health considerations in natural gas development.

Natural Gas Production and Reserves

Natural gas production basins stretch throughout at least 30 of the Lower 48, as well as in the Gulf of Mexico and California offshore, as shown in **Figure 1**. Between 1995 and 2003, total natural gas production in the Lower 48 averaged about 50 billion cubic feet per day (Bcf/d) and began to decline until 2005. Since then, natural gas production has been rising, reaching about 63 Bcf/d in 2011, representing a more than 20 percent increase in domestic natural gas production.

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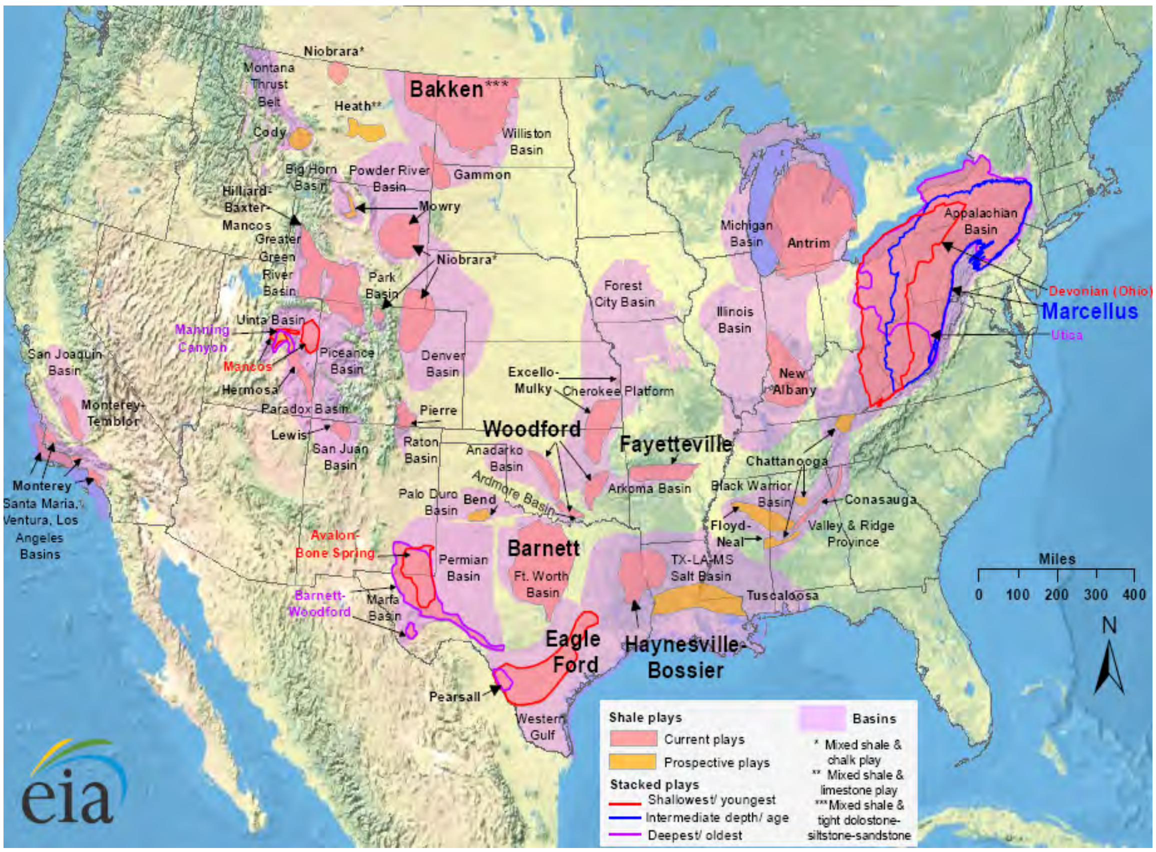
2 Hydraulic fracturing, combined with horizontal drilling, represents the combination of two existing technologies drilling down to deep shale or other tight rock formations (and then across them, exposing a larger pay zone than via vertical wells), and then cracking the rock open to allow natural gas to flow toward and up the well bore.

The age of natural gas basin development ranges from infant to mature. Some newer shale formations are now experiencing rapid development. The Eagle Ford in South Texas and the Haynesville that straddles the Louisiana-Texas border both began production in 2008. On the other end of the development spectrum, the San Juan and Permian basins have been producing since the 1920s.

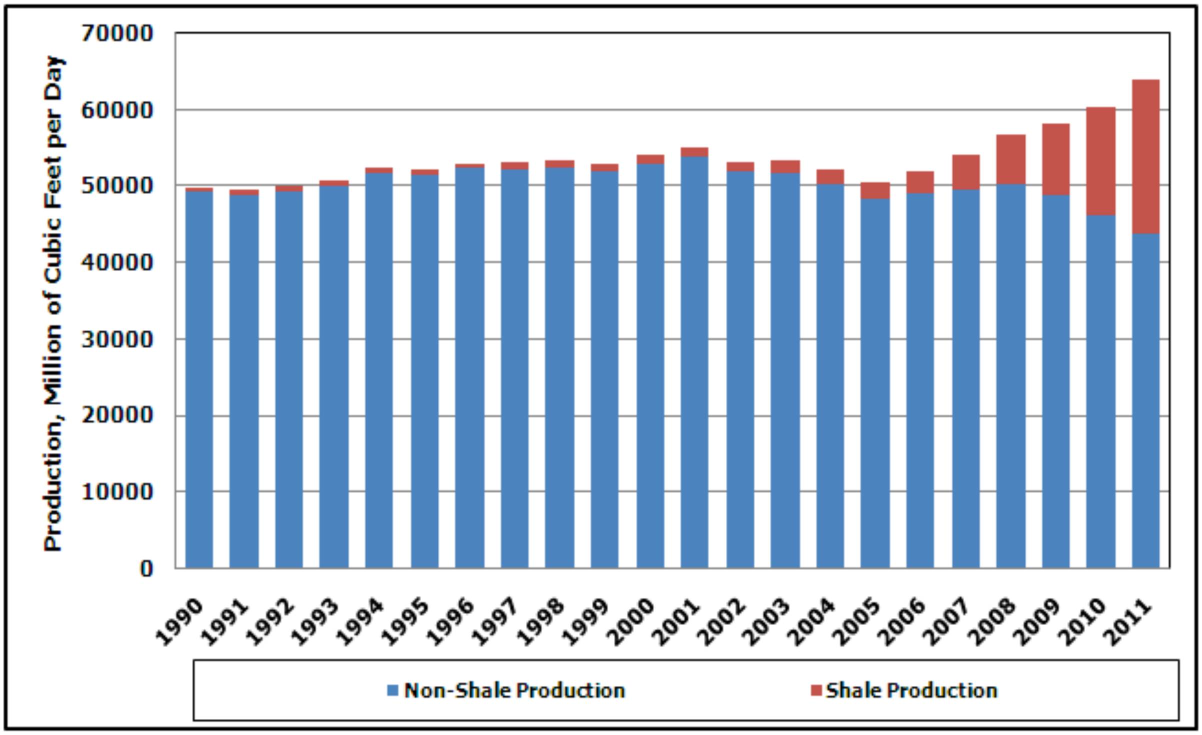
Figure 1: Production Basins in the Lower 48



Source: U.S. EIA.

Figure 2 and **Table 1** show that natural gas production is shifting from conventional sandstone basins to the low permeability (tight natural gas) sandstones and shale formations. Between 2000 and 2010, both the Permian and San Juan basins experienced declines in natural gas production, while production in the Mid-Continent, fueled by the development of the Barnett shale formation, increased dramatically, by about 90 percent. Natural gas production in the Rocky Mountains and the Eastern United States (particularly Pennsylvania) displayed a similar pattern, increasing by about 76 percent and 112 percent, respectively.

Figure 2: Lower 48 Natural Gas Production by Source



Source: Lippman Consulting, Inc.

The higher producing regions, shown in **Table 1,** are those containing shale and tight natural gas formations. The production trends shown in **Table 1** and **Figure 2** reflect the movement of capital into the development of shale and tight natural gas resources, which provide higher rates of return. The movement away from conventional resources is a result of this producer preference, not necessarily an indication that conventional resources are being depleted.

Natural Gas From Shale Formations

Production from shale formations predates current development. For more than 60 years, shale-deposited natural gas provided marginal production in the Appalachian and Illinois Basins. These formations, however, lacked sufficient effective permeability to allow large-scale production of natural gas. As a result, before the technological breakthroughs described below, only a few shale formations with sufficient natural fractures produced limited quantities of natural gas. Between 1995 and 1998, shale formations produced no more than 0.5 Bcf/d.

Table 1: Lower 48 Production by Region Plus Alaska

Natural Gas Production (Bcf/d)			
Region	**2000**	**2011**	**Percent Change**
West Coast	1,121	747	-33.4
Permian	5,040	4,140	-17.9
Rocky Mountain	6,283	11,047	75.8
San Juan Basin	4,309	3,301	-23.4
Gulf Coast	28,936	22,860	-21.0
Mid-Continent	8,322	15,822	90.1
Eastern United States	2,771	5,870	111.8
Alaska	1,150	1,002	-12.9

Source: U.S. EIA and Lippman Consulting, Inc.

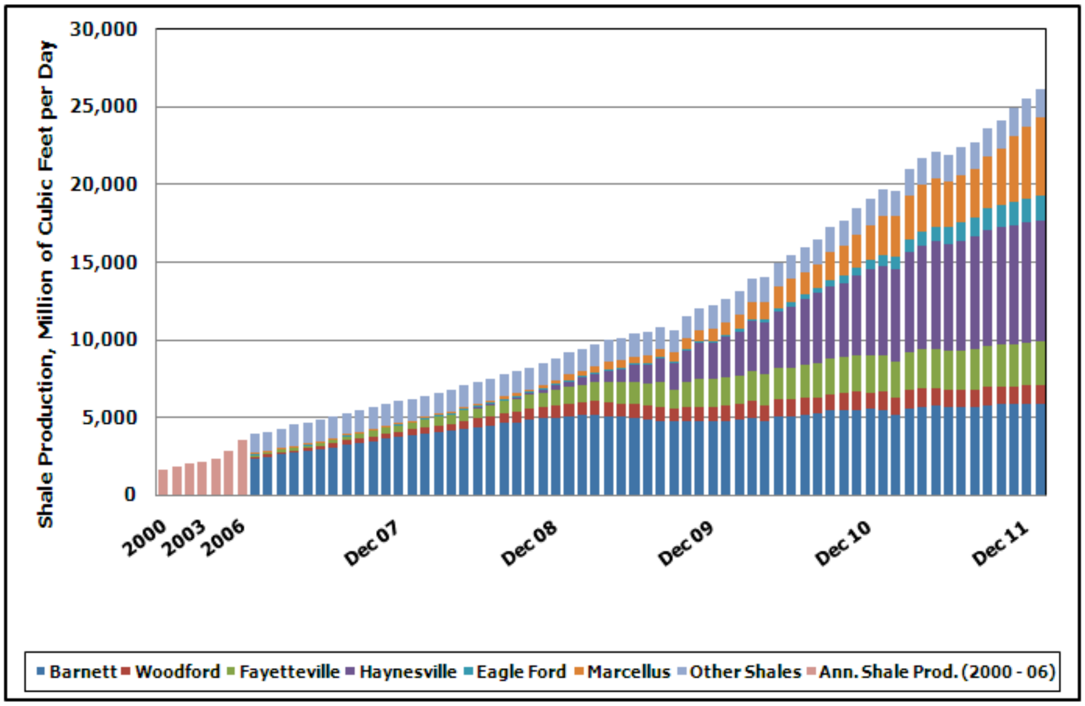
However, starting in 1998, development of the Barnett Shale increased production to more than 1 Bcf/d. This development was pioneered by independent producer Mitchell Energy, which is credited with years of experimenting with different combinations of fracturing liquids and pressures into the Barnett Shale formation to ultimately create what is now known as modern slick-water, high-volume fracking. Mitchell further combined this advanced fracturing technique with the relatively new ability (afforded by computer control) to drill horizontally. Extending the well bore laterally across a shale formation from a single well and fracturing multiple segments along this longer length allows a much greater exposure of the pay zone.[3] This, in turn, enhances drilling economics since it allows much higher production from the capital investment in a single well. Devon Energy purchased Mitchell in 2002 and began to apply the combined technique in other supply basins.[4] This innovative application and modification of the older relatively low-pressure Hydrafrac technique have unlocked access to large quantities of natural gas stored in low-

3 To produce natural gas a well is drilled down through the different layers of a geological formation to reach the reservoir that contains exploitable natural gas, also referred to as a pay zone.

4 An interview with former Mitchell Energy geologist and company officer Daniel Steward detailing Mitchell Energy's years of research in the Barnett shale can be found at http://thebreakthrough.org/blog/2011/12/interview_with_dan_steward_for.shtml. (Accessed April 2012.)

permeability shale formations.[5] **Figure 3** displays the natural gas production from shale formations by region.

Figure 3: Lower 48 Production From Shale Formations



Source: Lippman Consulting, Inc.

After 2001, Mitchell Energy's technique was applied to other shale formations, such as the Haynesville (Texas and Louisiana), the Marcellus (Eastern United States), the Fayetteville (Arkansas), the Woodford (Oklahoma), and the Eagle Ford (South Texas). As a result, shale production dramatically increased, averaging 16 Bcf/d in early 2011 and more than 25 Bcf/d in early 2012. Further, exploration and production companies are now applying the technique to other kinds of tight rock formations, such as the Granite Wash tight sandstone that stretches from Oklahoma into Texas.

As a result of rapid and extensive development, shale formations are contributing an increasing share of the natural gas production in the Lower 48. In 2000, shale formations contributed only about 2 percent of the total natural gas production in the Lower 48. By

5 *Hydrafrac* was the name coined by Standolind Oil and Gas in its patent of a fracturing technique that is widely cited as the first hydraulic fracturing job. See, for example, Montgomery and Smith, "*Hydraulic Fracturing: History of an Enduring Technology*," Society of Petroleum Engineers, December 2010. See http://www.spe.org/jpt/print/archives/2010/12/10Hydraulic.pdf. (Accessed April 2012.)

2010, production from shale formations reached about 23 percent and by early 2012 has reached about 38 percent.[6]

Natural Gas Resource Estimates

Natural gas resources underground can only be estimated because they cannot be seen directly. The many difficulties in understanding the nature and quantity of natural gas located subsurface in different reservoirs or rock formations make estimating natural gas resources an inexact science. Resource estimates measure geologic risk based on the probability that volumes of natural gas exist in earth's subsurface and that the industry, at some combination of technology and price, will be able to produce them. The ability to unlock shale formations, through the use of fracking and horizontal drilling, has eased some uncertainty and resulted in higher resource estimates. The industry uses four general classifications to describe resources, each corresponding to a different level of certainty about their ability to be produced. The following sections outline these classifications.

Proved reserves: The Potential Gas Committee (PGC) views this category as *"the quantities of natural gas that current analysis of geologic and engineering data demonstrate with reasonable certainty to be recoverable in the future from known … gas reservoirs under existing economic and operating conditions."*[7] Industry observers often characterize the estimated production from these resources as close to 90 percent certainty and consequently label this estimate as P90. These are resources for which sufficient drilling has occurred to delineate the reservoir and production tests (run from the wells) have been analyzed enough to be reasonably certain the formation will produce the estimated quantity at current technology and economics.[8]

Proved reserves are said to be:

- Geologically known and developed.
- Producible with current technology and economics.

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6 Lippman Consulting at http://www.lippmanconsulting.com/.

7 Exact classifications tend to vary with the source of the data. However, similar definitions are used by the U.S. Energy Information Administration (EIA), the Securities and Exchange Commission (SEC), and by the Society of Petroleum Engineers. The PGC does not estimate proved reserves, but instead focuses on resources outside the proved category.

8 The SEC allows producers to book the value of their reserves using an average price over the last 12 months. See, for example, http://www.sec.gov/divisions/corpfin/guidance/cfactfaq.htm#P279_57537 and Rule 4-10A. (Accessed April 2012.)

Potential resources: Natural gas resources that are not a proved reserve. These are divided into probable, possible, or speculative. In general, these reserves must meet the following criteria:

- Geologically known with decreasing levels of certainty.
- Not producible with current or foreseeable technology.

Probable resources: The PGC views this category as those *"… resources [that] are associated with known fields and are the most assured of potential supplies. Relatively large amounts of geologic and engineering information are available to aid in the estimation of resources existing in this category."* These resources are usually well extensions or new pools in existing fields.

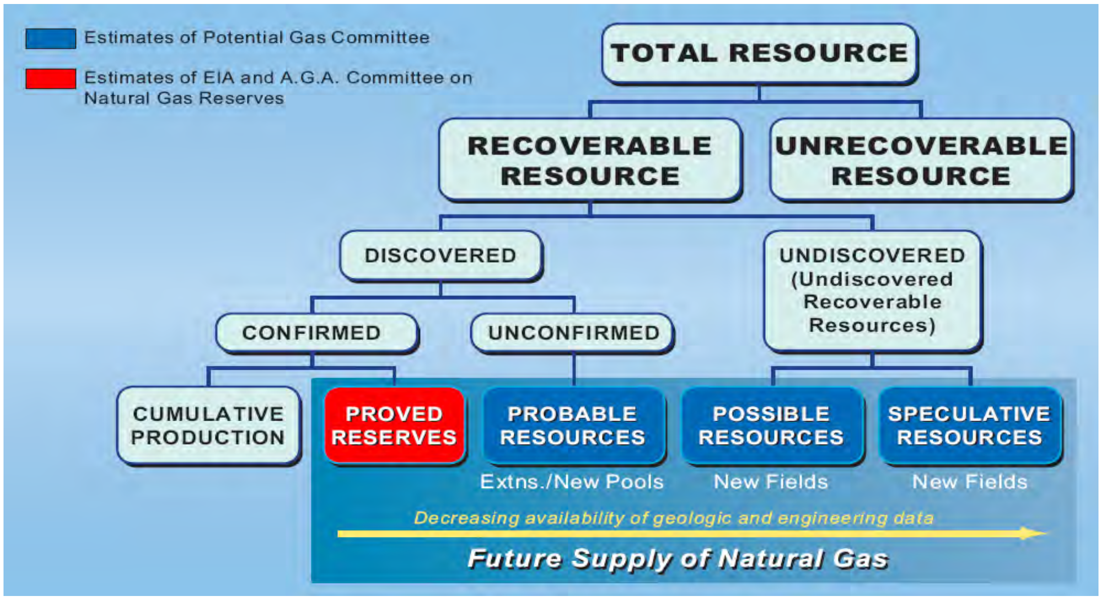
Possible resources: The PGC views this category as those *"… resources that are a less assured supply because they are postulated to exist outside known fields, but they are associated with a productive formation in a productive [region]. Their occurrence is indicated by a projection of plays or trends of a producing formation into a less well explored area of the same geologic [era]."* The probability of actual production of these resources equals or exceeds ten percent and usually involves finding new fields.

Speculative resources: The PGC views this category as those *"… resources [that] are expected to be found in formations or geologic provinces that have not yet proven productive."* The probability of actual production of these resources falls below 10 percent.

Figure 4 demonstrates the resource categories. The World Gas Trade Model (WGTM), used by staff to model alternate scenarios of natural gas production, trade, and prices, uses two categories of reserves: proved and the potential resource categories probable and possible.[9]

9 *2011 Natural Gas Market Assessment: Outlook,* Draft Staff Report, California Energy Commission, September 2011, CEC-200-2011-012-SD.

Figure 4: Reserve Categories From the Potential Natural Gas Committee



Source: Potential Gas Committee

The model inputs do not track identically to the PGC estimates due to the inexact nature of reserve estimation and the combinations of different elements. In general, the overall estimates fall into three broad categories:

- P90 (Conservative Estimate): Actual future production has a 90 percent probability of meeting or exceeding the estimated recoverable natural gas remaining in the subsurface.
- P50 (Most Likely Estimate): Actual future production has a 50 percent probability of meeting or exceeding the estimated recoverable natural gas remaining in the subsurface.
- P10 (Optimistic Estimate): Actual future production has a 10 percent probability of meeting or exceeding the estimated recoverable natural gas remaining in the subsurface.

Figure 5 displays proved natural gas reserves between 1999 and 2009. The United States natural gas industry has consistently added enough proved reserves to offset annual production and maintain a reserves-to-production ratio typically varying between 8 and 11 years.[10] The development of shale resources, however, has helped proved reserves to increase, from an annual growth rate of about 3.2 percent until 2004, to 7.4 percent thereafter.

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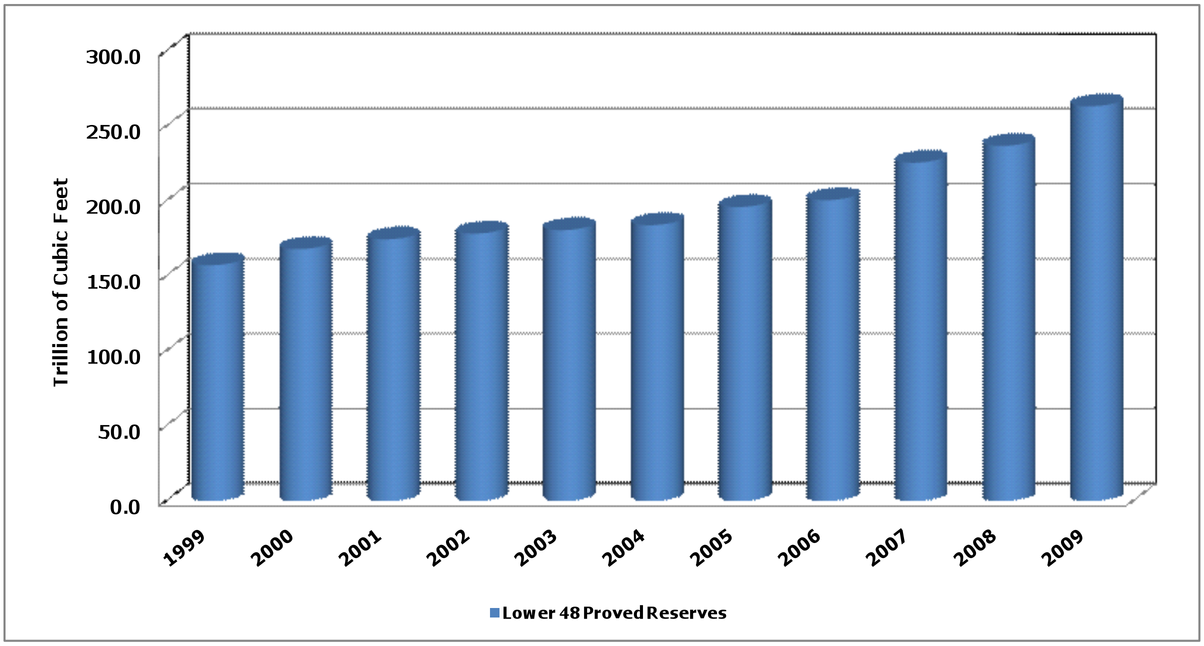
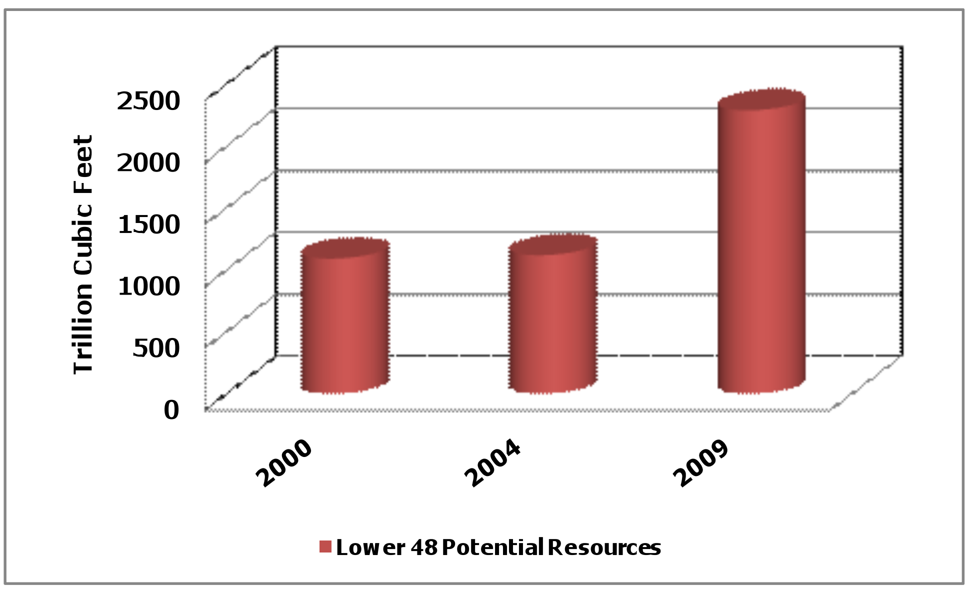
10 See U.S. EIA at http://www.eia.gov/dnav/ng/NG_ENR_DRY_A_EPG0_R11_BCF_A.htm.

Figure 5: Proved Reserves in the Lower 48



Source: U.S. EIA.

Figure 6: Lower 48 Potential Resources



Source: U.S. EIA and the Potential Gas Committee, 2008.

Figure 6 displays potential natural gas resources between 1999 and 2009. Few industry observers doubt the enormity of the original natural gas-in-place of shale formations, which has changed the resource profile of Lower 48 estimates of natural gas from producing basins.[11] Between 2000 and 2004, potential resources edged higher, growing at an annual average rate of 0.5 percent. However, developing shale formations pushed the annual average growth rate to 15.3 percent in 2009, resulting in total potential resources of 2,287 trillion cubic feet (Tcf).

Shale formation development is pushing overall natural gas resources to higher levels. The U.S. EIA estimates technically recoverable resources (proved and potential) for the United States from all natural gas formations at 2,543 Tcf, with 827 Tcf from shale formations.[12] To demonstrate the extent of natural gas resources, staff calculated the Reserves Life Index, which equals the sum measure of resources divided by current consumption. For the United States, using proved reserves plus probable resources, the current Reserves Life Index equals 111 years.[13] Changes in either the amount of resources or the rate of consumption will result in new estimates of the index. At present, shale development is expanding the resource base, and consumption remains stable; as such, the index is rising.

While production from the shale formations has dramatically increased, the full delineation of these formations is lagging since only more drilling can provide the necessary critical information to fully understand them. Estimating recoverable resources is thus inherently uncertain. The progression of development will help establish the boundaries of the shale formations, generating more precise estimations. Until then, uncertainties surrounding each factor produce inexact estimates of future production and recoverable resource potential.

North American Production and Reserves

Production and reserves of natural gas in Canada and Mexico influence natural gas prices in the Lower 48. A pipeline grid system connects the Lower 48 to both Canada and Mexico, although connections to Mexico lag that of Canada. Canadian shipments to the Lower 48 averaged 8,975 million cubic feet per day (MMcf/d), while the Lower 48 sent about 920 MMcf/d to Mexico.

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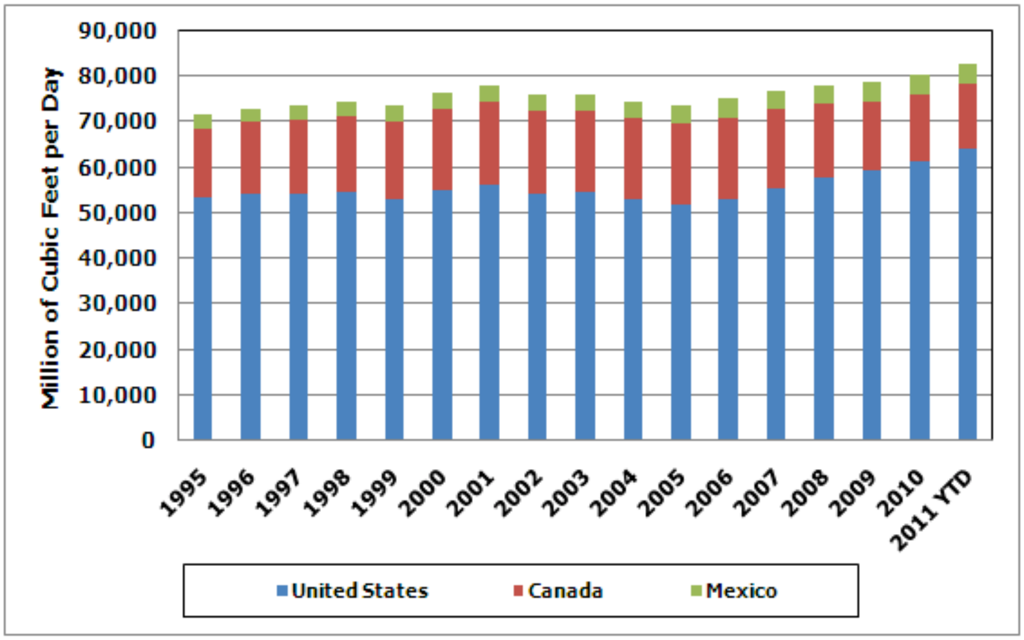
11 "Original gas in place" is the total volume of natural gas present in shale formations, which differs from and exceeds the total expected to be extracted. As indicated elsewhere, not all of that gas is technically or economically recoverable.

12 U.S. EIA, *Annual Energy Outlook 2011*, December, 16, 2010, Report #DOE/EIA-0383(2011) p 117 (total natural gas reserves) and p 79 (shale gas reserves) found at http://www.useia.gov/forecasts/aeo/assumptions/pdf/oil_gas.pdf.

13 This stands in contrast to the 12.5 years calculated from proved reserves only cited above.

Figure 7 shows North American production from 1995 to 2011, with production peaking in 2001 and then declining until 2005. Increases after 2005 are almost entirely attributable to natural gas from shale formations in the Lower 48, pushing production to more than 80,000 MMcf/d in 2011. **Table 2** shows the estimated technically recoverable natural gas supplies for North America, which consists of proved reserves plus potential resources as previously defined.

Figure 7: North American Production



Source: Lippman Consulting, Inc.

Table 2: Estimated Ultimate Recovery for North America and Reserve Life Index for Proved Reserves Plus Potential Resources[14]

	Technologically Recoverable (Proved Reserves Plus Potential Resources), Tcf		Current Consumption, Tcf/yr	Estimated Reserve Life Index, Years
	Shale	All Sources		All Sources
Mexico	681	874	2.1	416
Canada	388	734	3.0	245
United States	827	2,552	23.0	111
Total	**1,896**	**4,160**	**28.1**	**148**

Source: U.S. EIA; *The Potential Gas Committee*, 2008; Lippman Consulting, Inc.; and *2011 Natural Gas Market Assessment: Outlook*, Draft Staff Report, California Energy Commission, September 2011, CEC-200-2011-012-SR.

14 This table combines estimates from three sources and may not correlate precisely with published data from any one source.

Shale Gas Development Outside the United States

The U.S. EIA evaluated shale resources in 14 regions of the world and concluded that estimated technically recoverable resources exceed 6,600 Tcf.[15] Although outside the scope of this report, the development of shale-deposited natural gas around the world has significant geopolitical and economic consequences. For example, the development of shale-deposited natural gas in Europe could mean more LNG exports from Russia. This, in turn, could dampen prices in the continental United States and California, if some of Russia's increased exports end up competing with domestic production in the Gulf of Mexico. The following briefly summarizes selected country's shale resources:

Canada

Canada is developing several shale formations including:

- Horton Bluff, Utica, and Lorraine in Eastern Canada.
- Muskwa shale of the Horn River in Northeast British Columbia.
- Montney and Bakken shales in the Western Canadian Sedimentary Basin.

Production from the Horn River, Bakken, and Montney shales now exceeds 1,650 MMcf/d, and the U.S. EIA estimates that technically recoverable resources equal 388 Tcf.

Mexico

Mexico's state-owned oil company, PEMEX, tested its first shale well in the Eagle Ford, which stretches from South Texas into Northern Mexico. The well tested at a rate of 3.0 MMcf/d. The U.S. EIA estimates that technically recoverable resources equal 681 Tcf.

Europe

Both Poland and Sweden have identified viable shale formations and expect to begin development in the near future. The U.S. EIA places Poland's estimated technically recoverable resources at 187 Tcf and Sweden's at 41 Tcf.

China

China is beginning exploration on its large shale-deposited natural gas resources. The U.S. EIA estimated China's technically recoverable resources at 1,275 Tcf.

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15 U.S. EIA, "*World Shale Gas Resources, An Initial Assessment of 14 Regions Outside the United States,*" April 2011. Found at http://www.useia.gov/analysis/studies/worldshalegas/. (Accessed April 2012.)

Technology Development in Natural Gas Production

Technology development has impacted all stages of natural gas development. The enhanced productive capability of natural gas reservoirs, particularly shale formations, resulted from technological development in three areas:

- Exploration.
- Drilling (including surface preparation and casing the hole with pipe and cement).
- Well completion and stimulation.

Exploration for natural gas deposits intensified with the development of three-dimensional and four-dimensional seismic surveys. These new techniques allowed geologists and geophysicists to evaluate "chunks" of the earth's subsurface rather than two-dimensional slices. This capability boosted the industry's ability to find natural gas deposits and delineated the boundaries of identified deposits. According to the PGC, success rates on exploratory wells have climbed to about 65 percent in the late 2000s, up from about 30 percent in the late 1990s. Further, fracking and horizontal drilling have increased access to natural gas resources and expanded per-well recovery.

The marginal cost profile links the marginal cost of production to the quantity of reserves that economic agents can develop.[16] These costs represent the capital expenditures needed to expand the natural gas resource base and vary from location to location. These costs depend on two important parameters:

- Current state of knowledge of the resources.
- Current level of technology.

Figure 8, which compares cost profiles, demonstrates how fast and how much the picture of natural gas supplies and production technology has changed in recent years.[17] The profiles demonstrate that as marginal costs increase the amount of natural gas that is available for development and, thus, for production also increases.

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16 This represents the capital portion of the marginal cost of production. The operation and maintenance portion appears elsewhere in the WGTM.

17 These cost profiles were used by staff in its modeling for the years 2007 and 2011 in preparation of the *2011 Natural Gas Market Assessment: Outlook*, Staff Draft Report, California Energy Commission, September 2011, CEC-200-2011-012-SD.

Figure 8: Change in Marginal Cost Profile, 2007 to 2011

Source: Rice World Gas Trade Model, Baker Institute, and California Energy Commission, *2011 Natural Gas Market Assessment: Outlook*, Staff Draft Report, California Energy Commission, September 2011, CEC-200-2011-012-SD.

Technological improvements across the industry have pushed the overall supply cost curve to the right, increasing the amount of natural gas resources available at a given cost. For example, a reserve addition of 800 Tcf in 2007, at then-current conditions, would have cost about $7.00/Mcf (2005 – 2006 dollars). However, that same volume of natural gas reserve additions now costs only about $3.50/Mcf (2005 – 2006 dollars) under conditions in 2011.

The following narrative on the development of shale formations demonstrates how technological improvements can — and do — change the economics of energy development:

> Horizontal drilling and hydraulic fracturing are unlocking the continent's bountiful gas shale plays one by one, leading to a seismic shift in production economics — and prices will never be the same.[18]

Further discussion of economic issues related to the development of natural gas can be found in a 2009 Energy Commission report.[19]

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18 Peter Tertzakian, chief energy economist, ARC Financial Corp, reported in *Natural Gas Intelligence*, April 27, 2009.

19 Leon D. Brathwaite, *Shale-Deposited Natural Gas: A Review of Potential*, California Energy Commission, February 2010, CEC-200-2009-005-SF.

In the area of new well completion techniques, some industry operators are embracing "green completions," which reduce the amount of methane and volatile organic compounds escaping to the atmosphere. After fracking stimulation, the fracturing fluid flows back up the well bore to the surface. Methane and volatile organic compounds (VOCs) are mixed with the fracturing fluid and, when the fluid reaches the surface, escape to the atmosphere if not captured. Green, or reduced emissions, completions, capture the methane and VOCs through separation techniques at the wellhead. Certain states already require use of green completions, although Colorado's Rule 805, for example, requires them only when more than 500 Mcf of natural gas may escape and not if the capture is technically or economically infeasible.[20] The industry may be required to expand its use of green completion techniques under new regulations.

In mid-2011, the U.S. EPA issued for final comment a series of regulations designed to reduce air pollution from oil and natural gas operations.[21] Among the proposed rules is a requirement to capture VOCs during well completion for all hydraulically fractured or refractured wells, which will also capture the methane. The U.S. EPA estimates that only 25 percent of natural gas wells throughout the country are completed using techniques to capture fugitive emissions and says that the value of the captured methane will make the new rules pay for themselves.[22]

The American Petroleum Institute (API) filed comments on these rules, arguing for a two- to three-year phase-in period because the equipment needed to employ green capture techniques for all wells is not currently available. It argued that the new rules are not cost-effective and will slow down drilling.[23] U.S. EPA issued the final rules on April 18, 2012, which require use of green completion techniques "where feasible" and allow the industry to flare methane emissions at fractured wells until 2015. The rules are consistent with other actions by the federal government designed to address the ongoing opposition to hydraulic

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20 See, for example, http://cogcc.state.co.us/RR_Training/presentations/805_AirQuality.pdf, p. 8. (Accessed April 2012.)

21 The rules are proposed in Docket No. EPA-HQ-OAR-2010-0505 and are discussed in the Infrastructure section of this report because portions of the proposal apply to natural gas pipeline valves and compressor stations.

22 A fact sheet on the U.S. EPA proposed rule can be found at http://www.epa.gov/mats/pdfs/proposalfactsheet.pdf. (Accessed March 2012.)

23 API's original comments can be found at http://www.api.org/Newsroom/testimony/upload/2011-11-30-API-Oil-and-Gas-Rule-Final-Comments-Text.pdf. (Accessed March 2012). API issued follow-up comments in March saying it would seek a White House meeting to discuss the proposed rules. The March comments can be found at http://www.api.org/news-and-media/news/newsitems/2012/mar-2012/study-epa-air-emissions-rules-could-cause-slowdown-in-drilling-reduced-govt-revenue.aspx. (Accessed March 2012.)

fracturing and the effort to develop industry best practices, which will likely push producers to move toward greater use of green completion techniques. A more detailed description of new emissions rules for natural gas facilities is provided in Chapter 5.

Changing Industry Economics

Impact of Natural Gas Liquids

The presence of crude oil and natural gas liquids (NGL), such as propane, ethane, and butane, is increasing the economic feasibility of shale plays. In early 2011, Range Resources, a Dallas-based producer with major operation in several shale plays, published its overall finding and development (F&D) cost. The F&D cost dropped from $3.10 per thousands of cubic feet equivalent (Mcfe) in 2008, to $1.00 per Mcfe in 2009, and to $0.71 per Mcfe in 2010.[24] Range Resources typifies United States-based companies that are seeking lower F&D costs by pursuing natural gas liquids. Further, the U.S. EIA provided overall finding and development cost for the natural gas industry shown in **Figure 9**.

24 Range Resources, *Finding and Development Cost Calculations*, 2011. Range cites itself as having the lowest finding and development costs in its peer group. See http://www.rangeresources.com/Our-Company/Strategy.aspx. (Accessed April 2012.)

Figure 9: Overall Finding and Development Cost

Source: U.S. EIA.

Range Resources, in its April 2012 company presentation, cites an increase in revenue of nearly $4 per MMBtu for natural gas in liquids-rich plays after ethane extraction.[25] Natural gas producers are shifting their exploration and development dollars to liquid-rich properties:

- So-called “liquid corridor” of the Marcellus Shale
  - (NGL — about 5.0 gallons per Mcf)
- Bakken Shale in North Dakota and Montana
  - (NGLs — about 5.6 gallons per Mcf)
- Niobara Shale in Nebraska, Wyoming, and Colorado
  - (NGLs — about 5.6 gallons per Mcf)
- Granite Wash “tight” sandstone in Texas and Oklahoma
  - (NGLs — about 5.3 gallons per Mcf)

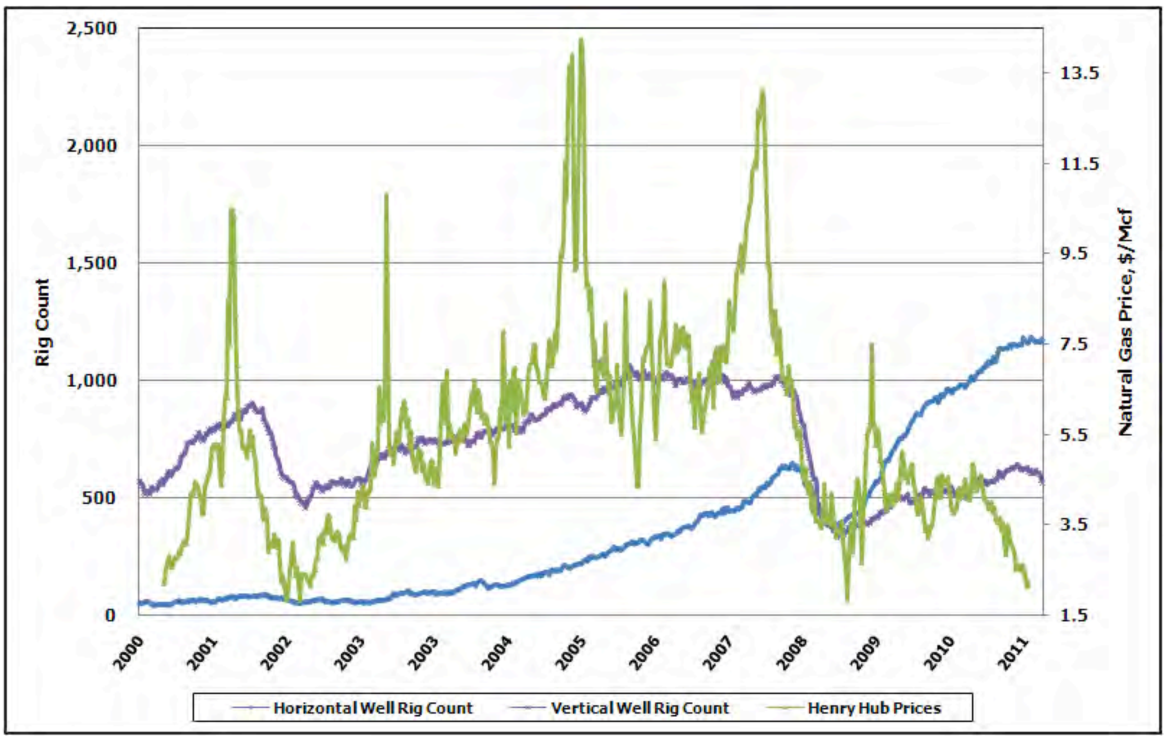
25 See http://phx.corporate-ir.net/phoenix.zhtml?c=101196&p=irol-presentations, p. 19. (Accessed April 2012.)

- Eagle Ford Shale in South Texas
    - (NGLs — about 5.2 gallons per Mcf and now producing more than 80,000 barrels per day of oil and natural gas liquids)
- Tuscaloosa Marine Shale in Texas, Louisiana, and Mississippi
    - untested

Further, the prospect of higher-than-average financial returns is attracting foreign capital. As a result, joint ventures with foreign entities are increasing. For example, the Korean National Oil Corporation recently entered into a joint venture with Anadarko Petroleum Company to develop Anadarko's Eagle Ford acreage. The Chinese National Offshore Oil Corporation has invested with American independent producers, including with Chesapeake Energy, in a deal to buy certain properties and help finance drilling in others.[26]

Figure 10 explores the relationship between level of investment (as represented by the horizontal rig count) and prices (as represented by Henry Hub spot prices).

Figure 10: Well Rig Count and Spot Prices



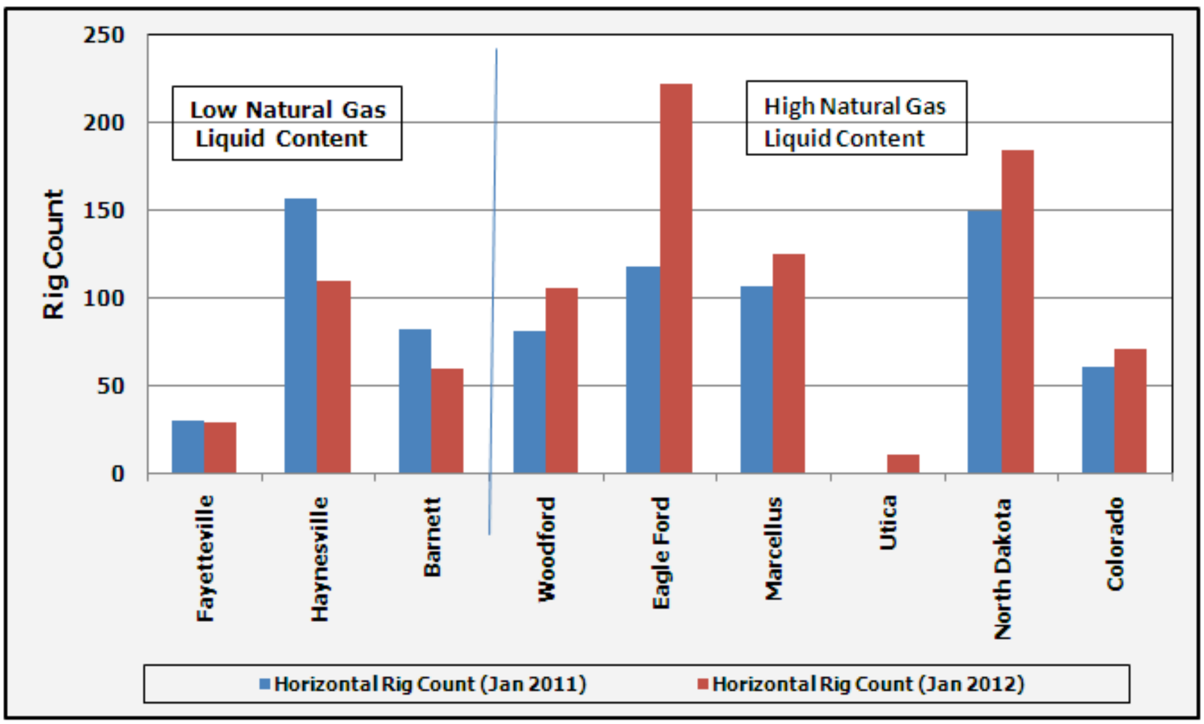
Source: Baker Hughes and U.S. EIA.

26 See, for example, http://dealbook.nytimes.com/2010/10/11/cnooc-in-2-2-billion-deal-with-chesapeake-energy/. (Accessed April 2012.)

In general, **Figure 11** shows that investments, represented by the active rig count, rise and fall with natural gas commodity prices. However, while the rig count of horizontal wells did decline in 2008, their recovery has surpassed precollapse level. Horizontal wells now occupy a larger percentage of all natural gas wells drilled.

Since industry operators extract natural gas, NGLs, and oil using horizontal wells, the rig count for horizontal wells now exceeds the rig count for vertical wells.[27] As such, the active rig count for vertical rigs has remained well below its precollapse level, capturing the phenomenon of capital dollars shifting from conventional formations to unconventional formations. Breakeven costs become "… even lower where natural gas liquids such as propane, ethane, and butane are present."[28]

Figure 11: Capital Investment Shift to "Oily" Plays



Source: *Natural Gas Week*, February 2012 and Lippman Consulting, Inc.

Figure 11 displays the shift in drilling as demonstrated by the change in the rig count, from regions with drier formations (for example, without crude oil or natural gas liquids) to those

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27 Dry natural gas wells produce only small quantities of NGLs.

28 Federal Energy Regulatory Commission (FERC) staff presentation by Christopher Ellsworth reported in the *Oil & Gas Journal*, October 2009.

that are wetter (for example, crude oil or natural gas liquids are present). Over the last year, capital investment has decreased in dry production formations such as the Fayetteville, the Haynesville, and the Barnett (shown on the left portion of **Figure 11**).[29] However, the formations with high liquid content, such as the Eagle Ford and the Marcellus, experienced dramatic increases in drilling (shown on the right portion of the chart). Also, North Dakota with the Bakken Shale and Colorado with the Niobrara Shale exhibited increases.

Environmental and Public Health Concerns

The development of shale formations has focused increased attention on the potential risk posed to the public health and to the environment by oil and natural gas operations. Stakeholders — regulators, citizens, environmental and local grass-roots groups, and industry representatives — are now discussing and studying the potential impact of the development of shale gas resources. In particular, their concerns are focused on the use of fracking needed to produce natural gas from shale and other tight formations.[30]

Development of several shale formations, for example, the Barnett shale near Fort Worth, Texas, is occurring near major population centers. As a result, more people are coming into direct contact with drilling operations. Some residents have not only complained about toxic air emissions, such as benzene and greater ground-level ozone, but argue that potential leakage of chemicals used in the fracking process — either at the surface, shallow subsurface, and deep surface aquifers — pose a health and safety risk and are calling for more disclosure and stricter regulation. Residents in less populated areas have also complained.

This section does not attempt to resolve these issues or even provide a comprehensive environmental discussion, but instead describes the key risks and concerns identified by stakeholders. The key impact of these concerns on natural gas supply trends is the creation of uncertainty for the expected magnitude and cost of natural gas market activities as potential moratoria, restrictions, or mitigation costs are imposed by various governments or regulators. The following sections discuss these general areas of environmental concerns including surface disturbances, GHG emissions, water use and disposal and associated

29 While production has shifted away from dry basins, reserves in those plays increased.

30 As recently as 2009, the general reaction to shale development by key government agencies was that shale development posed no new environmental concerns. See, for example, U.S. DOE (Office of Fossil Fuels), National Energy Technology Laboratory, *Modern Shale Gas Development in the United States: A Primer*, April 2009, p ES5. A 2004 U.S. EPA study was also often cited as finding that fracturing poses "little or no" risk to drinking water: U.S. EPA, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs,* June 2004 (EPA 806-R-04-003).

issues, potential groundwater contamination, increased seismic activity, and possible new regulations.

Surface Disturbance

Some amount of surface disturbance occurs with the drilling of any well, whether with vertical or horizontal rigs, or into conventional or unconventional resources. Ground must be leveled and cleared to allow setup of a drilling rig and a laydown area for casing string pipe, generators, construction crew sheds and other equipment, pits for temporary storage of drilling mud or cuttings, and other needs. Access roads to reach the well pad are built. Sometimes, on-site tanks are constructed to hold condensate or water that may be produced from the well. Ultimately, small-diameter natural gas gathering lines must be built to carry the produced natural gas away from each well and aggregate it for processing and delivery to bigger pipelines.

Shale and development of other tight natural gas formations require hydraulic fracturing, and the surface disturbance issues can become larger and take on a more industrial character. These wells create bigger drilling pad footprints to accommodate the extra space required for equipment, mixing the fracturing liquid, parking at the well site for trucks (bringing in water, sand, and chemicals for fracturing jobs), and impoundment pits or facilities to store or treat fracturing flowback liquid.[31] In addition, there are greater diesel emissions from the delivery trucks and generators to create the horsepower necessary to inject the fracturing liquid.

In some environmentally sensitive areas, such as parts of the Rocky Mountains or the Outer-Continental Shelf, federal moratoria prohibit drilling. According to the U.S. Department of Interior, an estimated 93 Tcf of natural gas and 3 billion barrels of oil remain outside development activity in the Rocky Mountains alone as a result of environmental restrictions[32] Where drilling is permitted, most states, including Ohio, Colorado, Montana, South Carolina, Indiana, Louisiana, Texas, Michigan, New York, and Pennsylvania, have restoration requirement rules. Even with the drilling restrictions and restoration rules, there are those who believe that oil and natural gas drilling does more environmental damage than recognized. The Wilderness Society, for example, recommends that "[a] more accurate estimate of economically recoverable natural gas should include a full accounting of all the

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31 During the fracturing process, water mixed with chemicals and sand (fracturing liquids) are injected into the wells. After the fracturing technique is performed, as much as 70 percent of the fracturing liquid flows back up the well, also referred to as flowback liquid.

32 U.S. DOI, Bureau of Land Management, *Scientific Inventory of Onshore Federal Lands' Oil and Gas Resources and the Extent and Nature of Restrictions or Impediments to Their Development*, 2006.

hidden, nonmarket costs, including the *costs associated with erosion*, *declining water and air quality*, and *loss of wildlife habitat*." [33]

The Natural Gas Supply Association (NGSA), on the other hand, points out that the industry can reduce surface disturbance by using new technologies. Smaller rigs decrease surface disturbance, and horizontal and directional drilling allows greater flexibility in rig placement.[34] The shift to horizontal drilling lessens the surface disturbance by requiring fewer wells to recover an equivalent amount of resource. According to the National Energy Board of Canada, "[t]he land-use footprint [of shale natural gas development] does not appear to be of significant concern beyond conventional operations, despite higher well densities, because advances in drilling technology allow for ten or more horizontal wells to be drilled from the same wellsite."[35] **Figure 12** demonstrates this phenomenon.

However, some of the environmental impact assessments cite well pads used for fracking as being much larger than those used for conventional wells. The *Draft Generic Environmental Impact Statement* by the New York State Department of Environmental Conservation, for example, described well pads for fracturing using as much as 7.4 acres versus half an acre for conventional wells.[36] As more wells are drilled to meet increasing demand over time, continued concern about surface disturbance and the associated impacts to habitat and wildlife can be expected.

Greenhouse Gas Emissions

According to the U.S. EIA, consumption of natural gas resulted in about 21 percent of the carbon dioxide emitted in the United States in 2008.[37] Most of these emissions occur during the combustion of this fossil-based fuel, and when compared with other fossil-based fuels, combustion of natural gas produces about half the carbon dioxide emissions of coal.[38] Yet

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33 Pete Morton, Ph.D., et al., *Energy and Western Wildlands: A GIS Analysis of Economically Recoverable Oil and Gas*, 2002 (emphasis added).

34See http://www.naturalgas.org/environment/technology.asp#advances.

35 National Energy Board (Canada), *A Primer for Understanding Canadian Shale Gas*, November 2009.

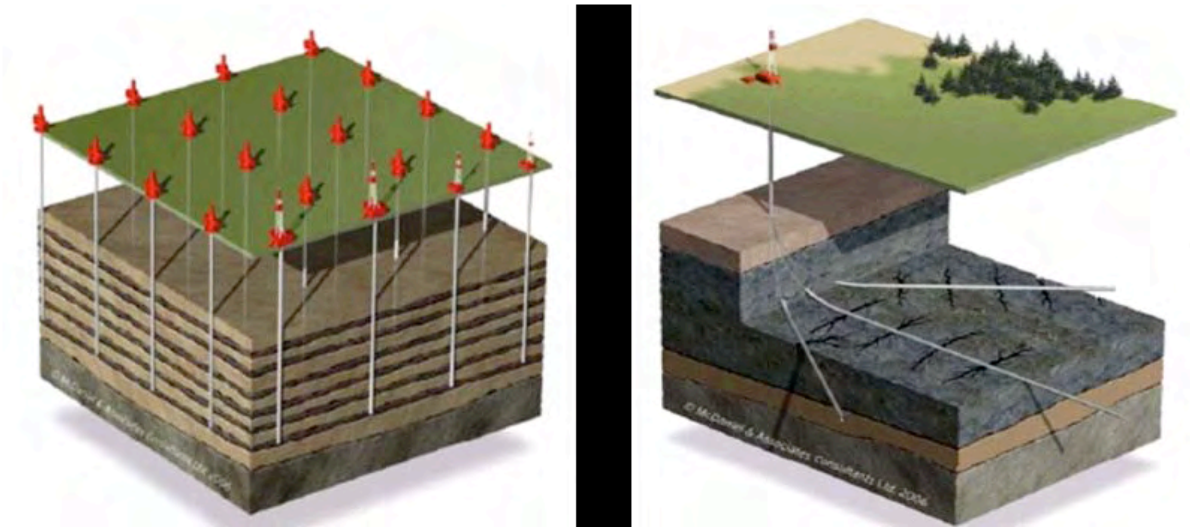
36 New York DEC *Draft GEIS* released September 7, 2011, Chapter 5, p. 8. Found at http://www.dec.ny.gov/docs/materials_minerals_pdf/rdsgeisch50911.pdf. (Accessed April 2012.)

37U.S. EIA, *Emissions of Greenhouse Gases Report,* 2008. Found at http://205.254.135.24/oiaf/1605/ggrpt/carbon.htmlhttp://205.254.135.24/oiaf/1605/ggrpt/carbon.html. See Table 5, *U.S. Carbon Dioxide Emissions from Energy and Industry, 1990 to 2008*. (Accessed April 2012.)

38 U.S. EPA, *Unit Conversions, Emissions Factors, and Reference Data*, p. 2. Found at http://www.epa.gov/cpd/pdf/brochure.pdf. (Accessed April 2012.)

methane itself, the prime constituent of natural gas, is a far more potent GHG than is carbon dioxide: about 23 times more potent over a 100-year period.[39]

Figure 12: Relative Comparison of Surface Disturbance



Source: American Natural Gas Alliance at: http://anga.us/media/206825/hydraulic%20fracturing%20101.pdf.

In early 2010, a team at Cornell University (the Howarth team) began posting preliminary analysis and notes on its website arguing that natural gas, on a life-cycle basis, emits more GHG than coal.[40] In late 2011, its formal article appeared in published form.[41] The claim was, and remains, controversial. On a *per* MMBtu basis, total emissions from natural gas produced from shale formations do not differ from that of natural gas from conventional sources when combusted. And while methane can and does leak at any stage of the entire process leading to consumption, the Howarth team's key point is that hydraulic fracturing gives shale-produced natural gas a poorer carbon footprint than coal. The reason is the methane gas that is released when the fracking fluid flows back up to the surface and the plugs that separate fracturing stages within the well bore are drilled out. In fact, the Howarth team asserts that shale and tight natural gas wells produce fugitive emissions that

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39 See http://www.epa.gov/outreach/qanda.html#2. (Accessed April 2012.)

40 Robert W. Howarth, *Preliminary Assessment of the Greenhouse Gas Emissions from Natural Gas obtained by Hydraulic Fracturing*" Found at http://www.technologyreview.com/blog/energy/files/39646/GHG.emissions.from.Marcellus.Shale.April12010%20draft.pdf. (Accessed April 2010.)

41 Robert W. Howarth, R. Santoro, and A. Ingraffea, *Methane and the Greenhouse-Gas Footprint of Natural Gas From Shale Formations, Climatic Change,* 2011, DOI 10.1007/s10584-011-0061-5.

average 1.9 percent of the projected lifetime production of the wells, three times more than for conventional wells.

Another Cornell team led by L. M. Cathles (the Cathles team) takes issue with the Howarth team's findings.[42] One of the Cathles team's objections is that the Howarth team calculations rely on the U.S. EPA's 2010 Technical Support Document that contains data the U.S. EPA appears to have obtained during Natural Gas STAR technical workshops for five formations gathered from 2004 to 2010.[43] Additionally, Howarth's finding that the footprint of shale gas is at least 20 percent greater than that of coal rests on methane's global warming potential over only 20 years instead of 100 years. The Cathles team also notes that if you make the comparison in terms of CO_2e per Mwh — which reflects the relative heat rates of the natural gas-fired versus coal-fired units used to generate electricity — the conclusion that natural gas is more GHG-intensive than coal evaporates. While predating the Cornell dispute, even the National Energy Board of Canada indicated that "…the potential growth in CO_2 emissions from shale gas development needs further investigation and, if necessary, mitigation action."[44]

Ultimately, rules to reduce volatile organic compounds, methane, and chemicals known as "air toxics" emitted during production and transportation processes by the oil and natural gas industry, along with green completion rules, will help resolve the issue. However, Howarth cautions that the cost of capturing emissions is uncertain and wells that are not connected to pipelines are not subject to the rules.[45] The U.S. EPA emissions rules are addressed in greater detail in Chapter 5.

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42 L.M. Cathles, L. Brown, A. Hunter and M. Taam, "A Commentary on The Greenhouse-Gas Footprint of Natural Gas in Shale Formations" *Climatic Change*, January 2012, DOI 101007/s10584-011-0333-0.

43 The Technical Support Document (TSD) can be found at http://www.epa.gov/climatechange/emissions/downloads10/Subpart-W_TSD.pdf. (Accessed April 2012.) This is the same TSD U.S. EPA is relying on to support the proposed oil and gas VOC capture requirement discussed previously herein. IHS CERA has a paper out criticizing how U.S. EPA gathered the emissions data: "*Mismeasuring Methane: Estimating Greenhouse Gas Emissions from Upstream Natural Gas Development*." See http://www.ihs.com/products/cera/energy-report.aspx?AliasID=2412018.

44 National Energy Board (Canada), *A Primer for Understanding Canadian Shale Gas*, November 2009, p 23.

45 Robert W. Howarth, et al., "Venting and Leaking of Methane From Shale Gas Development: Response to Cathles et al.," *Climatic Change*, February 2012, DOI 10.1007./s10584-012-0401-0.

Water Use and Disposal and Associated Issues

Fracking uses fresh water as the primary constituent of the fracking liquid. Chesapeake Energy says its deep hydraulically fractured well uses an average of 4.5 million gallons of water.[46] **Figure 13** displays a typical water-use cycle in fracking stimulation. Water can be provided by a variety of sources, including rivers, lakes, groundwater, private water, wells, or municipal water supplies, or it can be water recycled from a previous fracturing job. After the fracturing technique is performed, as much as 70 percent of the fracturing liquid flows back up the well and must be treated for reuse or disposed of. If not well-managed, the large water requirements for these stimulation processes pose potential risks to the environment. Spillage of the water mixed with chemicals, sometimes called slickwater, can occur.

An evaluation of the chain of water movement highlights the risk. The chain of water movement occurs in five steps:

- Natural gas operators identify a source and obtain withdrawal rights.
- Truckers haul water to well site.
- Operators pump water (along with sand and chemicals) into formation of interest.
- Operators collect flowback water from the well upon conclusion of fracturing and store in on-site pits.
- Truckers haul away water for disposal or recycle.[47]

Under conditions of high–withdrawal, low stream flow, water extractions for oil and natural gas operations can stress aquatic life and complicate water use in areas where other uses – such as fishing and other recreational activities, municipal water supplies, and requirements at power plants – compete for the same water supplies. Some jurisdictions, Arkansas for example, are exploring and implementing mitigating alternatives such as permitting freshwater withdrawals and storage, if necessary, but only when stream flows exceed a specified minimum. Such regulatory policies can ease the complication of competing water uses.

Further, oil and natural gas operators haul most of the water to the well site. Because of the added traffic volume, increased truck journeys have raised concerns with some local communities about added mobile emissions, along with associated noise and dust, and the

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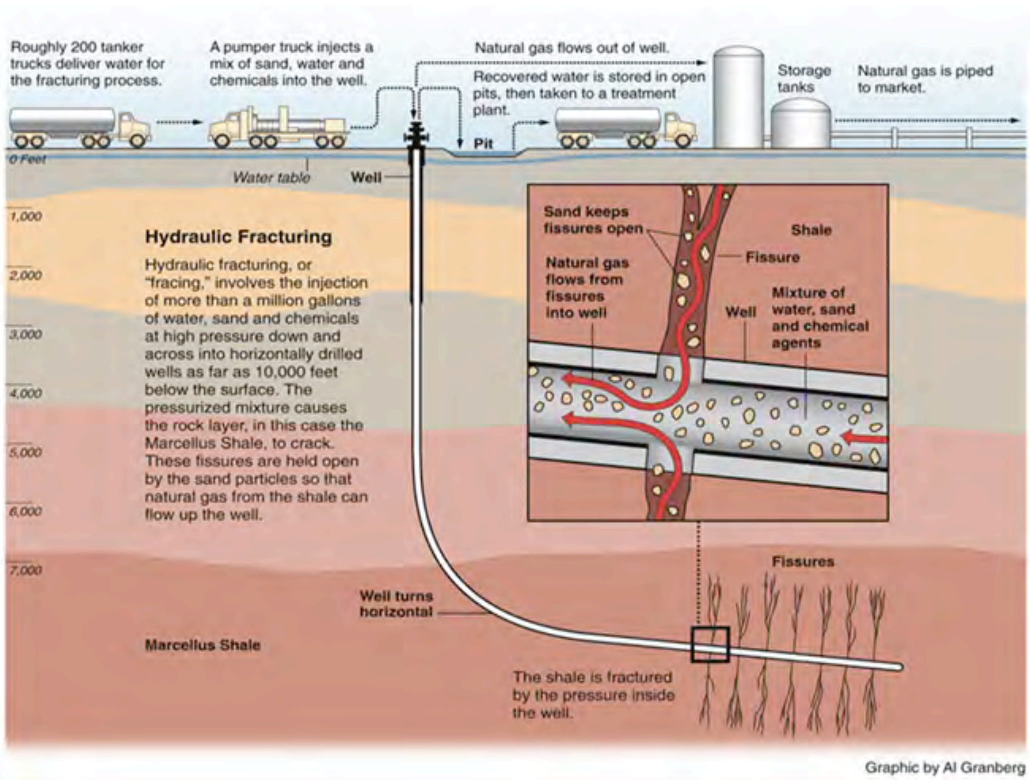
46 See http://www.hydraulicfracturing.com/Water-Usage/Pages/Information.aspx. (Accessed April 2012.) The API says in an industry guidance document that the average shale well uses 2 to 4 million gallons of water. See API, *Water Management Associated with Hydraulic Fracturing*" p 5. Found at http://www.shalegas.energy.gov/resources/HF2_e1.pdf. (Accessed April 2012.)

47 Industry operators must clean flowback water before reusing it in a hydraulic fracturing stimulation.

additional adverse impact upon the roads. The Massachusetts Institute of Technology points to two mitigating actions by the natural gas industry:

- Reuse of flowback wastewater can and does significantly reduce the road traffic associated with hauling water, which represents much of the traffic movement.
- Large-scale operators are also using pipelines to transport water to site, further reducing the amount of road traffic.[48]

Figure 13: Water-Use Cycle in Hydraulic Fracturing



Source: U.S. EIA.

For example, in some areas where shale development has surpassed infancy, "…pipelines have been constructed to transport produced water to injection well disposal sites. This

48 Massachusetts Institute of Technology, *The Future of Natural Gas*, June 2011, p. 44.

minimizes trucking the water and the resultant traffic, exhaust emissions, and wear on local roads." [49]

Further, depending on the jurisdiction, states and local governments may have developed rules to protect groundwater and surface resources. These government entities regulate water disposal by requiring the oil and natural gas industry to manage its ultimate fate through underground injection, treatment and discharge, or recycle. The Marcellus Shale development uses all three methods of disposal.

The U.S. DOE examined this issue and concluded that:

> [s]tates, local governments, and shale gas operators seek to manage produced water in a way that protects surface and ground water resources and, if possible, reduces future demands for freshwater. By pursuing the pollution prevention hierarchy of "Reduce, Re-use, and Recycle," these groups are examining both traditional and innovative approaches to managing shale gas produced water. This water is currently managed through a variety of mechanisms, including underground injection, treatment and discharge, and recycling.[50]

Also,

> [i]njection disposal wells are permitted under the Federal Safe Drinking Water Act (SDWA), the Underground Injection Control (UIC) program (or in the case of state primacy, under equivalent state programs), a stringently permitted and monitored process with many environmental safeguards in place. Hydraulic fracturing is otherwise specifically exempt from SDWA by virtue of an amendment to the 2005 Energy Policy Act. Several bills in Congress that would rescind this exemption are unlikely to proceed until the U.S. Environmental Protection Agency (EPA) completes its study of risk to drinking water from hydraulic fracturing.[51]

Potential Groundwater and Aquifer Contamination

The potential contamination of groundwater and underground aquifers raises another environmental concern. As previously discussed, a typical multistage fracking treatment requires between 2 million and 4 million gallons of freshwater treated with chemicals that facilitate both the suspension of the proppant (sand, most times) and the lubrication of the

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49 U.S. DOE (Office of Fossil Fuels), National Energy Technology Laboratory, *Modern Shale Gas Development in the United States: A Primer*, April 2009, p. 68.

50 Ibid.

51 Ibid.

conveying mediums.[52] The fluid that an operator pumps into formations of interest consists of 99.5 percent sand and water and 0.5 percent chemicals. In the development of an entire field (shale or tight sandstone), the amount of water injected into a shale formation could reach into the hundreds of millions of gallons.[53] In the initial flowback, field operators retrieve between 30 and 70 percent of the injected water.[54] The rest remains within the formation and flows back over time with the produced natural gas. A good place to start addressing these concerns is by understanding well construction and opportunities for exposure of surface water and underground aquifers to fracturing liquids.

Figure 14 illustrates a typical well design. As shown, casing pipe made of steel sealed with cement isolates the groundwater aquifers from the well bore. Between 2005 and 2009, the industry drilled more than 120,000 natural gas wells.

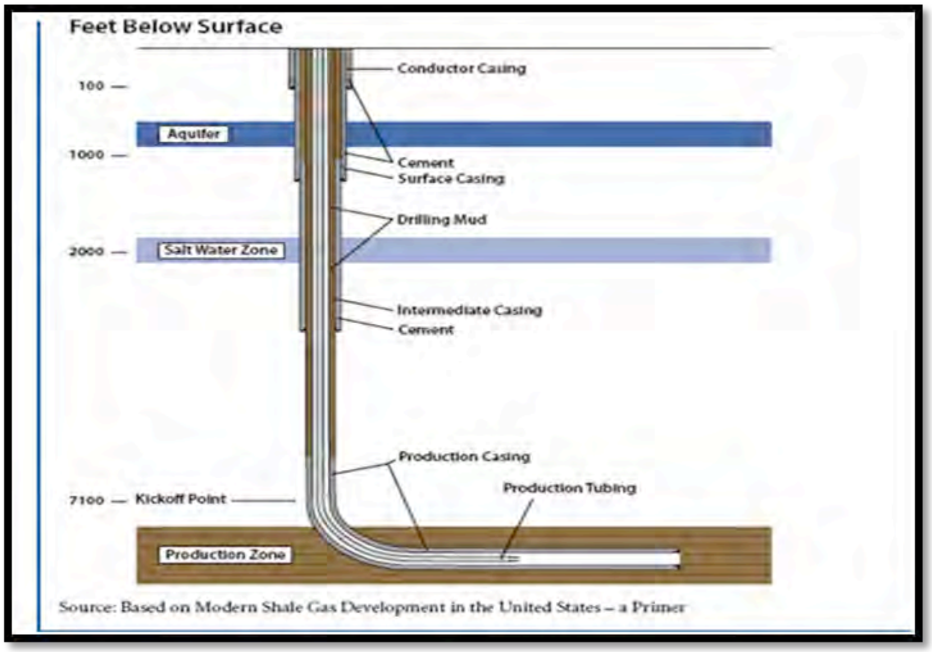
52 A proppant is a material that will keep an induced hydraulic fracture open, during or following a fracturing treatment, to allow extraction of the natural gas.

53 The volume of water used in the development of natural gas from shale formations raises other environmental concerns, including the consumption of large water quantities and recovered water disposal.

54 See Robert W. Howarth "*Venting and Leaking of Methane From Shale Gas Development: Response to Cathles et al.*," *Climatic Change*, DOI 10.1007/s10584-012-0401-0, January 2012, p. 5. Howarth's original article has a table that shows the number of days of flowback after fracturing for each of the five sets of data in his sample. The number of days of flowback ranges from 5 to 12, depending on the well and basin. But in his response to Cathles in January 2012, Howarth has a sentence referring to an average of 10 days of flowback, which mathematically is not the average between 5 and 12. Those not reading both articles may not note this discrepancy.

Table 3 shows the widely reported environmental impact incidents in this period.

Figure 14: Typical Well Design for Protecting Groundwater



Source: The Future of Natural Gas, MIT.

MIT concluded "[i]n the studies surveyed, no incidents are reported which conclusively demonstrate contamination of shallow water zones with fracture fluids."[55]

Also, the Ground Water Protection Council, a nonprofit association of state agencies responsible for environmental safeguards related to ground water, testified in 2009 before the United States House of Representatives that reports of groundwater contamination due to fracking "… are not accurate."[56]

55 MIT, *The Future of Natural Gas*, June 2011, p 44.

56 Statement of Scott Kell, on behalf of the Ground Water Protection Council, House Committee on Natural Resources Subcommittee on Energy and Mineral Resources, Washington, D.C., June 4, 2009.

Table 3: Widely Reported Incidents Involving Natural Gas Drilling (2005 – 09)[57]

Type of Incident	No. of Incidents
Groundwater Contamination by Natural Gas or Drilling Fluids	20
On-Site Surface Spills	14
Off-Site Disposal Issues	4
Water Withdrawal Issues	2
Air Quality	1
Blowouts	2

Source: The Future of Natural Gas, MIT.

Some states, including Texas, Louisiana, New York, and Pennsylvania, have issued regulatory requirements for "responsible development" of oil and natural gas formations.[58] These regulations include guidelines for the use and disposal of water, the protection of groundwater, and the disclosure and use of chemicals. Further, the regulatory requirements[59] include:

- Review of each drilling application for environmental compliance.
- Complete environmental assessment of all proposed oil or natural gas wells that are within 2,000 feet of municipal water wells.
- Strict review of the well design to ensure groundwater protection.
- On-site inspection of drilling operations.
- Enforcement of strict restoration rules when drilling ends.

In August 2009, Louisiana's Commissioner of Conservation developed safeguards and regulations for natural gas exploration and production, particularly in the urban areas of the Haynesville, one of the major shales in the Lower 48. In Pennsylvania, Kathleen McGinty, former Secretary of the State's Department of Environmental Protection, speaking about the regulatory framework, said "…these rules are in place to protect our natural treasures and

57 Massachusetts Institute of Technology, *The Future of Natural Gas*, June 2011.

58 Department of Environmental Conservation, New York State, *Final Scope for Draft Supplemental Generic Environmental Impact Statement on Oil, Gas and Solution Mining Regulatory Program*, 1992.

59 Ibid.

we will not compromise on them."[60] In 2008, the department's inspectors ordered the partial shutdown of two drilling sites after discovering violations of state regulations.[61] Since then, the state has dealt with a major spill of fracturing fluid and, at least, one well blowout.

Several government agencies are exploring possible links between fracking and groundwater contamination, including the U.S. EPA and several state agencies such as Pennsylvania's Department of Environmental Protection. Duke University's Nicholas School of the Environment also has a study underway.

In December 2011, the U.S. EPA released for public comment and peer review a draft report of its investigation into possible groundwater contamination by hydraulically fractured wells drilled near Pavillion, Wyoming. [62] The report was prepared in response to several complaints by well owners of objectionable taste and odor in well water. The U.S. EPA notes internal inconsistencies about whether the taste and odor problems were concurrent with or after the fracking, and concurs with recommendations to take samples before fracturing to create baseline data to evaluate against after fracturing.[63]

Domestic well samples confirmed the presence of methane and dissolved hydrocarbons, and more dissolved methane in domestic wells located close to natural gas production wells. Samples from shallow monitoring wells subsequently found gasoline range organics, diesel range organics, and BTEX (benzene, tolulene, ethylbenzene, and xylenes). Some or all of these wells were located near surface pits "previously used for the storage/disposal of drilling wastes and produced and flowback waters." The findings led U. S. EPA to drill deep monitoring wells to investigate further. Natural gas samples from those wells led the U. S.EPA to conclude that "the explanation best fitting the data for the deep monitoring wells is that constituents associated with fracking have been released into the Wind River drinking water aquifer at depths above the current production zone."[64] They also state that "[t]he groundwater in Pavillion, WY contains chemicals that are normally used in natural gas production practices, such as hydraulic fracking."

Not surprisingly, many in the industry, including Encana, the driller of the natural gas wells at Pavillion, disagree with the finding and question the U.S. EPA's well construction and sampling method. On March 8, 2012, the U. S. EPA, along with the Wyoming Governor and the Northern Arapaho and Eastern Shoshone Tribes, issued a statement indicating that they

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60 Kathleen McGinty, Former Secretary of Pennsylvania's Department of Environmental Protection, speaking at a department-sponsored summit, June 2008.

61 *Environmental News Service*, June 16, 2008.

62 U.S. EPA, "*Investigation of Ground Water Contamination Near Pavillion, Wyoming,*" EPA 600/R-00/000.

63 U.S. EPA, p. 39.

64 U.S. EPA, p. 33.

would conduct, with help from the United States Geological Survey (USGS), further sampling of the deep monitoring wells drilled by the U.S. EPA for the Pavillion groundwater study.

In the meantime the study remains out for public comment, but convening the peer review panel has been delayed until the U.S. EPA and the USGS complete the additional samples. One of the most interesting findings by the U.S. EPA was that the surface well casing in the production wellbores "showed little or no cement over large vertical instances." That cement casing is key to preventing fracturing liquid from accessing underground aquifers. Industry often argues that fracturing doesn't cause contamination — rather, it is failure of the cement. The University of Texas study cited below also makes this case.

Duke University's Nicholas School for the Environment has a comprehensive discussion of fracturing issues on its website.[65] In addition, the school released a study in April 2011, led by Stephen Osborne and Robert Jackson, reporting they had found methane levels 17 times higher in wells located near fracking sites versus those that were not.[66] Industry sources such as *Energy In Depth* criticized the study for not comparing well samples pre-and post-fracturing. The Duke team also issued a policy paper with recommendations similar to those of the U.S. DOE Shale Gas Production Subcommittee discussed further below, including recommendations for further study.

Most recently, the University of Texas, Austin's Energy Institute issued its study *Separating Fact from Fiction in Shale Gas Development*.[67] With participation from the Environmental Defense Fund in developing the scope of work and methodology, the institute found that many of the reports of contamination can be traced to above-ground spills or wastewater mishandling that are common to all natural gas and oil operations.

Nonetheless, Anthony Ingraffea of the Howarth team at Cornell recommends performing a more complex, fundamental study of the long-term impacts of fracturing. Ingraffea and Duke's Robert Jackson both question whether enough is known about how natural gas migrates and, in particular, about a phenomenon known as "fracture communication." Fracture communication occurs when new wells connect with other wells in ways not expected. In a May 2010 Safety Advisory, the British Columbia Oil and Gas Commission advised drilling operators that predicting how the fissures from fracturing will propagate is

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65 See http://www.ces.ncsu.edu/lee/Natural%20Gas/ShaleGasRegulationbyStates4-10-11.pdf.

66 Osborne, et al., *Methane Contamination of Drinking Water Accompanying Gas-Well Drilling and Hydraulic Fracturing*, Nicholas School for the Environment, Duke University. Found at http://www.nicholas.duke.edu/hydrofracking/Osborn%20et%20al%20%20Hydrofracking%202011.pdf. (Accessed April 2012.)

67 Groat et al., *Separating Fact from Fiction in Shale Gas Development*. Found at http://energy.utexas.edu/index.php?option=com_content&view=article&id=151:shale-gas-regulation&catid=1:features&Itemid=146. (Accessed April 2012.)

difficult because drilled wells may have weakened a formation such that fracture lengths exceed design expectations.[68] The Safety Advisory cited 18 fracture communication incidents. Ingraffea recommends extensive modeling that "can iterate a scenario of multiple wells, multiple fracks, and gas and liquid movements" over several days of a fracturing job and within an appropriate distance of a fracturing job.[69] The modeling should also look at cumulative impacts on the well casing integrity.[70]

Disclosure is the other key area of activity. FracFocus is a voluntary industry effort in collaboration with the Ground Water Protection Council that allows citizens to look up the composition of fracturing liquids used at individual well sites. Sometimes, however, certain constituents of the fracturing liquids are labeled "not disclosed." A number of states are imposing rules to require the disclosure of chemicals used in fracking, although the specificity of those rules varies. In California, the State Legislature is considering a bill (Assembly Bill 591) that would require such disclosure.

Increased Seismic Activity

The other phenomenon attracting headlines and scientific study is an increase in seismic activity in regions where fracking is occurring. Some of these regions are not known for high levels of seismic activity or experienced little such activity until oil and natural gas production of shale formations using fracking began.

Magnitude 3 quakes were detected in the Barnett Shale around Dallas-Fort Worth in late 2008. A joint team from Dallas' Southern Methodist University and the University of Texas, Austin, linked the quakes to the injection of fracturing waste fluids into a saltwater zone located beneath the Barnett Shale producing zone near the DFW airport. That injection commenced about six weeks before the first of the noticeable-magnitude quakes. The joint team concluded that the wastewater injection was a "plausible cause" of the seismicity but questioned why other wastewater injection wells appeared not to have caused quakes. Team members said they did not know enough about the porosity and permeability of the zone where the wastewater was left or about the fluid path. [71] In a subsequent article, the

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68 British Columbia Oil and Gas Commission, *Safety Advisory 2010 – 03* found at http://www.bcogc.ca/document.aspx?documentID=808&type=.pdf. (Accessed April 2012.)

69 C. Mooney, "The Truth About Fracking", *Scientific American*, November 2011, pp. 80-85.

70 See Smith-Heavenrich, "Cornell Professor Wants EPA to Take Closer Look at Fracturing Technology," *Broader View Weekly*, March 3, 2011. Found at http://www.tiogagaslease.org/images/BVW_03_03_11.pdf. (Accessed April 2012.)

71 C. Frolich, et al., *Dallas-Fort Worth Earthquakes Coincident with Activity Associated with Natural Gas Production*, *The Leading Edge*, *Society of Exploration Geophysicists*, March 2010. Found at http://smu.edu/newsinfo/pdf-files/earthquake-study-10march2010.pdf. (Accessed April 2012.) SMU's

team said "[b]ecause of the absence of previous historical earthquakes, the proximity of the brine disposal well, and the similarity with other documented cases of induced seismicity, it seems likely that fluid injection induced the 2008–2009 sequence."[72]

Arkansas' Fayetteville Shale experienced a swarm of quakes in late 2010 and early 2011. The University of Memphis' Center for Earthquake Research and Information worked with the Arkansas Geological Survey to investigate the cause. The Center for Earthquake Research and Information noted the possibility of the underlying fault producing a 5.7 magnitude quake and while the agencies said "[t]here is only circumstantial evidence that links current earthquakes with waste water injection in central Arkansas, we are concerned that continued operation of injection wells in the seismic area risks triggering more and possibly larger earthquakes."[73] The Arkansas Oil and Gas Commission (AOGC) ordered the closure of several underground injection disposal sites. In February 2011, the AOGC ordered a moratorium on new injection wells and ordered operators to collect data about injection pressures and quantities injected.[74] After injections stopped, the swarm subsided, increasing at least the perception that the quakes were caused by the injection. Public information about the status of that work is difficult to obtain, but staff believes work is continuing while the moratorium is in place.

Oklahoma and Ohio have also experienced quakes. In Ohio, a swarm culminating in a 2.7 magnitude quake occurred on Christmas Eve 2011, and a 4.0 magnitude quake occurred on New Year's Eve 2012 in Youngstown. The Ohio Department of Natural Resources (ODNR) had already begun working with Columbia University's Lamont-Doherty Earth Observatory (Lamont-Doherty) to study the swarm when the holiday quakes occurred. Seismographs placed near a Class II deep injection well (9,184 feet) that began injecting in December 2010 allowed seismologists to confirm the epicenter as 2,454 feet below the injection well. (All of the 11 prior swarm events had been clustered within a mile of the well.) Based on the Lamont-Doherty preliminary findings, ODNR sought and obtained an

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announcement of the study summarizing its findings can be found at http://www.smu.edu/News/2010/dfw-earthquake-study-10march2010. (Accessed April 2012.)

72 C. Frolich, et al., "The Dallas–Fort Worth Earthquake Sequence: October 2008 through May 2009," *Bulletin of the Seismological Society of America*, February 2011, Vol. 101, No. 1, pp. 327–340. Found at ftp://ehzftp.cr.usgs.gov/brocher/EPA/FrohlichBSSA2011.pdf. (Accessed April 2012.)

73 "CERI Public Statement on the Guy Earthquake Swarm," found at http://www.ceri.memphis.edu/GUY/index.html. (Accessed April 2012.) Note that Arkansas is part of the New Madrid fault zone which is believed to be possible of producing infrequent but devastating quakes and which invariably heightens quake concerns in that area. See http://www.newmadrid2011.org/ for more information.

74 See http://www.aogc.state.ar.us/Hearing%20Orders/2011/Jan/602A-2010-12.pdf.

immediate halt to injections at the well. The ODNR researchers' findings identify the factors that they believe must be present to induce an earthquake:

- A fault must already exist within the crystalline basement rocks.
- That fault must already be in a near-failure state of stress.
- An injection well must be drilled deep enough and near enough to the fault and have a path of communication to the fault.
- The injection well must inject a sufficient quantity of fluids at a high enough pressure and for an adequate period of time to cause failure, or movement, along that fault (or system of faults).[75]

ODNR concluded that several earthquakes in northeastern Ohio resulted from the "injection of gas-drilling wastewater into the earth." As a result, ODNR issued new regulations for drillers in Ohio. These regulations include:

- Well operators must submit more comprehensive geological data when requesting an injection well drill site.
- The chemical makeup of all drilling wastewater must be tracked electronically.[76]

In Oklahoma, a swarm of more than 50 quakes culminated in a January 2011 magnitude 5.6 temblor. Various press reports cite seismologists arguing for or against the quakes being related to fracking. The Oklahoma Geological Society (OGS) has an open report file available.[77] Of the various reports on seismicity, the OGS open file is the only one linking the onset of fracturing (as opposed to the injection of wastewater post-fracturing) to seismic activity. According to the report:

> The strong correlation in time and space as well as a reasonable fit to a physical model suggest that there is a possibility these earthquakes were induced by

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75 Ohio Department Of Natural Resources, *Preliminary Report On The Northstar 1 Class Ii Injection Well And The Seismic Events In The Youngstown, Ohio, Area*, March 2012, pp. 2-3. Found at http://ohiodnr.com/downloads/northstar/UICreport.pdf. (Accessed April 2012.)
76 Additional details about the new rules can be found at http://www.ohiodnr.com/home_page/NewsReleases/tabid/18276/EntryId/2711/Ohios-New-Rules-for-Brine-Disposal-Among-Nations-Toughest.aspx. (Accessed April 2012.)

77 Holland, "Examination of Possibly Induced Seismicity from Hydraulic Fracturing in the Eola Field, Garvin County, Oklahoma," *Oklahoma Geological Society, Open-File Report OF1-2011*, p. 1. Found at http://www.ogs.ou.edu/pubsscanned/openfile/OF1_2011.pdf. (Accessed April 2012.)

> hydraulic fracturing. However, the uncertainties in the data make it impossible to say with a high degree of certainty whether or not these earthquakes were triggered by natural means or by the nearby hydraulic fracturing operation.[78]

Finally, in late April 2012, the USGS announced that its team of seismologists would be presenting a paper titled "*Are Seismicity Rate Changes in the Midcontinent Natural or Manmade?*" at the annual meeting of the Seismological Society of America.[79] They found many more quakes beginning in 2009, consistent with the wider application of hydraulic fracturing to shale formations outside the Barnett Shale. The USGS seismologists conclude that the quakes are manmade. They explain that underground injection of the waste liquid after fracturing counteracts the normal frictional forces that otherwise prevent very old, deep faults that from moving and instead "pries them apart" so that they slip.[80]

The seismologists say that the fracturing itself does cause small quakes, known as "microseismicity." These quakes are too small to cause damage and are reasonably well-understood because seismic measurements are used during fracturing to help guide the fracturing process. It is the permanent disposal of liquids by injection after fracturing that leaves the liquids underground long enough for them to lubricate faults and produce quakes big enough to feel that have increased in frequency. The seismologists say that they do not believe the lubrication will produce quakes capable of producing major damage, but that this question needs more study. In addition, the rate of injection and injection pressure may affect the seismic response. The seismologists conclude their abstract by stating that "it remains to be determined how [the quakes] are related to either changes in extraction methodologies or the rate of oil and gas production."

Possible New Federal and State Regulations

With the fracturing issues outlined above in mind, Energy Secretary Steven Chu appointed a Shale Gas Subcommittee to his Advisory Board and charged it with "identifying measures that can be taken to reduce the environmental impact and to help assure the safety of shale gas production." The subcommittee issued its first 90-Day Report on August 18, 2011, identifying 20 recommendations that the subcommittee "believes, if implemented, would assure that the nation's considerable shale gas resources are being developed responsibly, in

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78 Ibid.

79 W. L. Ellsworth, S. H. Hickman, A. L. Lleons, A. McGarr, A.J. Michael, J.L. Rubenstein, *Are Seismicity Rate Changes in the Midcontinent Natural or Manmade?*, USGS, Menlo Park, CA, April 2012. Publication pending. More information about USGS' release of the study can be found at http://www.usgs.gov/blogs/features/usgs_top_story/is-the-recent-increase-in-felt-earthquakes-in-the-central-us-natural-or-manmade/?from=title. (Accessed April 2012.)

80 See the USGS FAQ at http://earthquake.usgs.gov/learn/faq/?categoryID=46. (Accessed April 2012.)

a way that protects human health and the environment and is most beneficial to the nation." Many of the recommendations encourage the industry to develop and apply best practices related to disclosure and mitigation of local environmental impacts, background water quality measurements, repair of defective well cement jobs, capture of fugitive methane emissions, reduce the use of diesel engines at well pads, and disclose fracturing fluid composition and other measures.[81] The subcommittee issued its second 90-Day Report on November 18, 2011, reiterating the recommendations and expressing concern that insufficient action was being taken to implement the original recommendations:

> Absent action there will be little credible progress in toward reducing the environmental impact of shale gas production, placing at risk the future of the enormous potential benefits of this domestic energy resource.[82]

Further,

> It is the Subcommittee's judgment that if action is not taken to reduce the environmental impact accompanying the very considerable expansion of shale gas production expected across the country – perhaps as many as 100,000 wells over the next several decades – there is a real risk of serious environmental consequences and a loss of public confidence that could delay or stop this activity.[83]

In addition to the advisory panel effort and the oil and natural gas rules under consideration at the U.S. EPA, Interior Secretary Ken Salazar sent rules to the White House Office of Management and Budget that he proposes the U.S. Department of Interior adopt for fracking on federal land. In hearings before the House Natural Resources Committee in February 2012, Salazar has said the rules would be issued for comment and that they could possibly provide a template for national standards.[84] On May 4, 2012, the U.S. Department of Interior released proposed rules that include requirements for companies to publicly disclose the chemicals used in hydraulic fracturing on federal and Indian lands. In addition, the proposed rules contain measures that ensure well-bore integrity to prevent release of fluids in fracturing and confirm that waste management plans are in place for handling fracturing fluids. Once published in the Federal Register, there will be a 60 day public comments period on the proposed rules.

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81 Both 90-Day Reports can be found at http://www.shalegas.energy.gov/index.html. (Accessed April 2012.)

82 Secretary of Energy Advisory Board, Shale Gas Production Subcommittee, *Second 90-Day Report*, p. 3.

83 Subcommittee, *Second 90-Day Report*, p. 10.

84 See, for example, http://naturalresources.house.gov/News/DocumentSingle.aspx?DocumentID=278317. (Accessed April 2012).

To coordinate actions across federal agencies, President Obama issued an Executive Order on April 13, 2012, creating an interagency working group to "Support Safe and Responsible Development of Unconventional Domestic Natural Gas Resources."[85] The working group will be chaired by the Domestic Policy Council. Creating the working group was among the suggestions that had been made by the API in its public comments and statements, both on the oil and natural gas VOC capture rules under consideration by the U.S. EPA, referenced earlier, and the rules that the Interior Department is developing for fracturing on federal lands.

Staff has not compiled a comprehensive list of all potential rules under consideration in all states where fracturing occurs, as the list would be very long and change too rapidly to be useful. That being said, the Interstate Oil and Gas Compact Commission does post on its website regulations applicable by state and highlights efforts at adopting new regulations.[86] In addition, there is at least one bill pending in Congress that would prohibit federal regulation of hydraulic fracturing by declaring that states have the sole authority to regulate fracturing. The bill is Senate Bill 2248, known as the "Fracturing Regulations are Effective in State Hands Act," authored by Sen. James Inhofe (Republican, Oklahoma). Insider newsletters such as *The Hill* suggest the bill is not likely to progress.

As stated earlier, staff's expectation is that the industry and parties will ultimately address these issues given the prominence natural gas is being given in national energy policy, as exemplified by the U.S. DOE advisory board subcommittee. In the meantime, these issues add uncertainty to assessing future activity in the natural gas markets and will continue to bear close monitoring.

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85 See http://www.whitehouse.gov/the-press-office/2012/04/13/executive-order-supporting-safe-and-responsible-development-unconvention. (Accessed April 2013.)

86 The Interstate Oil and Gas Compact Commission state highlights can be found at http://groundwork.iogcc.org/topics-index/hydraulic-fracturing/hydraulic-fracturing-regulations. (Accessed April 2012.)

CHAPTER 3: Natural Gas Price Trends

Natural gas prices have declined substantially in the last few years, following several years of high prices, marked by significant price spikes. The interaction of supply and demand conditions is a key factor in determining prices. Quite often, however, speculation plays a significant role in the market. Recent low natural gas prices are largely attributed to high natural gas production as large amounts of shale gas have entered the market, in combination with low demand from the very mild winter and very high storage volumes.

While natural gas prices have declined recently, it is unclear how the natural gas industry will respond to these low price levels. Some in the industry are speculating that reduced exploration and drilling activities, as well as shutting-in of wells, could bring upward pressure on prices. Several other factors could contribute to increased prices going forward, including new regulation of financial markets and higher costs from necessary pipeline safety improvement following the San Bruno natural gas explosion. Finally, there are questions about whether exports of LNG from the United States will be approved, which some believe could lead to higher prices by exposing the United States natural gas market to higher world natural gas and oil prices.

This chapter describes in general how and where natural gas is priced as it moves from the wellhead to the end user, recent trends in natural gas prices, and significant issues that may affect natural gas prices going forward. Throughout this chapter, natural gas infrastructure (such as pipelines and storage) is discussed to emphasize pricing issues. A more detailed description of natural gas infrastructure is presented in Chapter 5.

How and Where Natural Gas Is Priced

Natural gas is purchased by heat content rather than by volume. Natural gas prices are quoted in units of millions of British thermal units (MMBtu), in therms (th), in decatherms (Dth), or in thousands of cubic feet (Mcf).[87] Natural gas is priced at various points along its

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87 Most residential customers typically see $/Dth on their gas usage bill. Note that 1 Dth = 10 therms = 1 MMBtu. 1 Mcf is roughly equal to 1 MMBtu. (In this report, the authors use the conversion factor of 1 Mcf = 1.030 MMBtu). Natural gas meters measure volume, and pipeline delivery capability is described in volume terms, because that is what goes through the meter orifice. But agents in the market, including end users, actually purchase MMBtus, whether it be a standard wholesale purchase agreement, a futures contract, or shown on a customer's gas bill. Part of the reason is that the heat content of the natural gas (measured in MMBtus) varies across different wells, so natural gas prices need to reflect this variation.

journey from the wellhead to the end -user, reflecting the costs incurred at each stage along the way. The physical activities of natural gas explorers, producers, processors, interstate and intrastate pipeline transporters, storage field operators, and distributors are all reflected in the prices. There are also different kinds of natural gas market transactions, including spot purchases and futures contracts. The prices of these transactions reflect the different obligations involved in the sale and the activities (and expectations) of market commodity exchanges, traders, speculators, and purchasers who all interact in complex ways to maximize their interests and minimize their uncertainty-related risks.[88]

The spot price of natural gas is the price paid on the open market (spot market) for near-term physical delivery of the natural gas; no continuing agreement is required with spot natural gas purchases. Another common natural gas price is the futures price, sometimes called a *futures contract*. Futures contracts are agreements bought and sold on the New York Mercantile Exchange (NYMEX) for deliveries of natural gas from 1 to 36 months in the future.[89]

Natural gas purchased on NYMEX is not always consumed by the purchaser; NYMEX contracts can be purchased to reduce the risk inherent to commodities. Natural gas that is bought and sold on NYMEX can change hands several times before it reaches the end user for consumption. Market speculators may also purchase natural gas on NYMEX to make a profit. Speculators use their knowledge to earn money through speculating as to future market price movements. Additional information on the regulation of financial markets for natural gas is presented later in this chapter and Appendix B.

There are many different locations or pricing points where natural gas can be purchased. These pricing points (market hubs) tend to be locations where prices are posted on a public index or exchange (such as NYMEX or IntercontinentalExchange [ICE]). They are generally “liquid” markets, where many trades occur each day and where ownership transfer of the natural gas can occur (generally at a pipeline interconnection). All natural gas pricing points are connected to at least one natural gas pipeline. Prices will vary for different market hubs due to the different costs of extraction of the natural gas marketed there and the different costs of processing and transporting the natural gas.

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88 Two of the most well-known commodity exchanges that trade energy products are the NYMEX and the ICE. Other exchanges include: Commodities Exchange (COMEX), Chicago Board of Trade (CBOT), and Chicago Mercantile Exchange (CME).

89 The NYMEX became part of CME group in 2008. The CME group was created and CBOT merged in 2007.

Delivered Price of Natural Gas

The delivered price of natural gas includes the cost of the commodity and the cost of transportation. The commodity price of natural gas is most commonly defined as the price of natural gas at a certain location plus any transportation costs up to that point. When natural gas purchased at one point is then transported to somewhere else, that would be considered a cost of transportation. For example, natural gas purchased at the California border at Malin would be considered a commodity price of natural gas even though the cost of transportation to get the natural gas to Malin from where it was produced is included in the price. If the entity who purchased this natural gas at Malin wants to use it at as fuel at a natural gas power plant, it would pay for the transportation to the power plant. The transportation cost to send the natural gas to the power plant would be considered the transportation rate (or cost of transportation) of natural gas.

Since transportation costs (rates) are regulated by the FERC for interstate pipelines and the California Public Utilities Commission (CPUC) for intrastate pipelines, these rates do not have the price volatility that spot commodity prices have in the market. Transportation rates are more stable than commodity prices and generally increase at the rate of inflation each year. However, higher expenses, public safety measures, and environmental issues can lead to significant uncertainty about what future transportation costs might be.

Figure 15 illustrates a natural gas flow diagram on the PG&E system from the wellhead to the end user. It demonstrates how transportation rates are added in each step to the commodity price of natural gas from the wellhead price to the end user. The price data in **Figure 15** are from December 2011.[90] Current natural gas commodity prices are lower than December prices. **Figure 15** shows that end users of natural gas pay both a commodity and a transportation component of their natural gas, and different end use customers pay different amounts for their transportation. Residential customers pay the most, while electric generator customers pay the least.[91]

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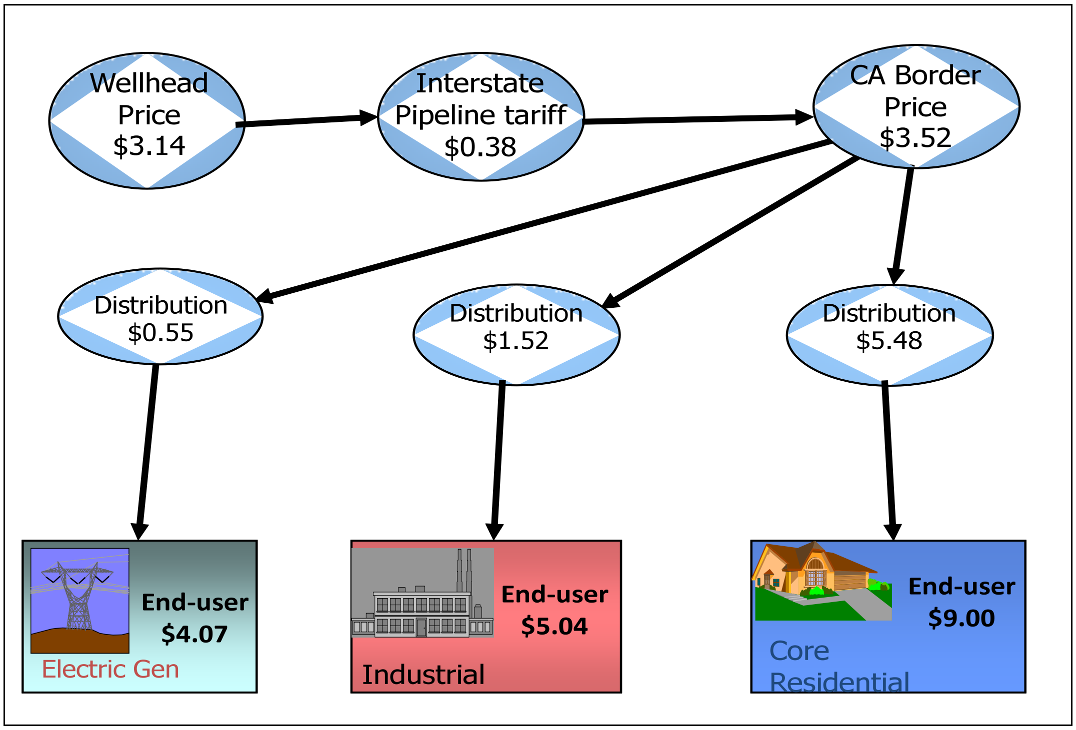
90 U.S. EIA.

91 Transportation for residential customers includes many smaller distribution lines, meters, compressors, and administration needs. Electric generation customers receive gas on large diameter transmission/distribution lines with fewer meter, compressors, and administration needs as compared to residential customers. In addition, gas used by residential customers generally travels farther than does gas going to electric generators. Because of these reasons, electric generation customers pay less for transportation than do residential customers. Industrial customer transportation rates fall in between residential and electric generation rates for similar reasons.

Figure 15: Natural Gas Flows and End-Use Prices

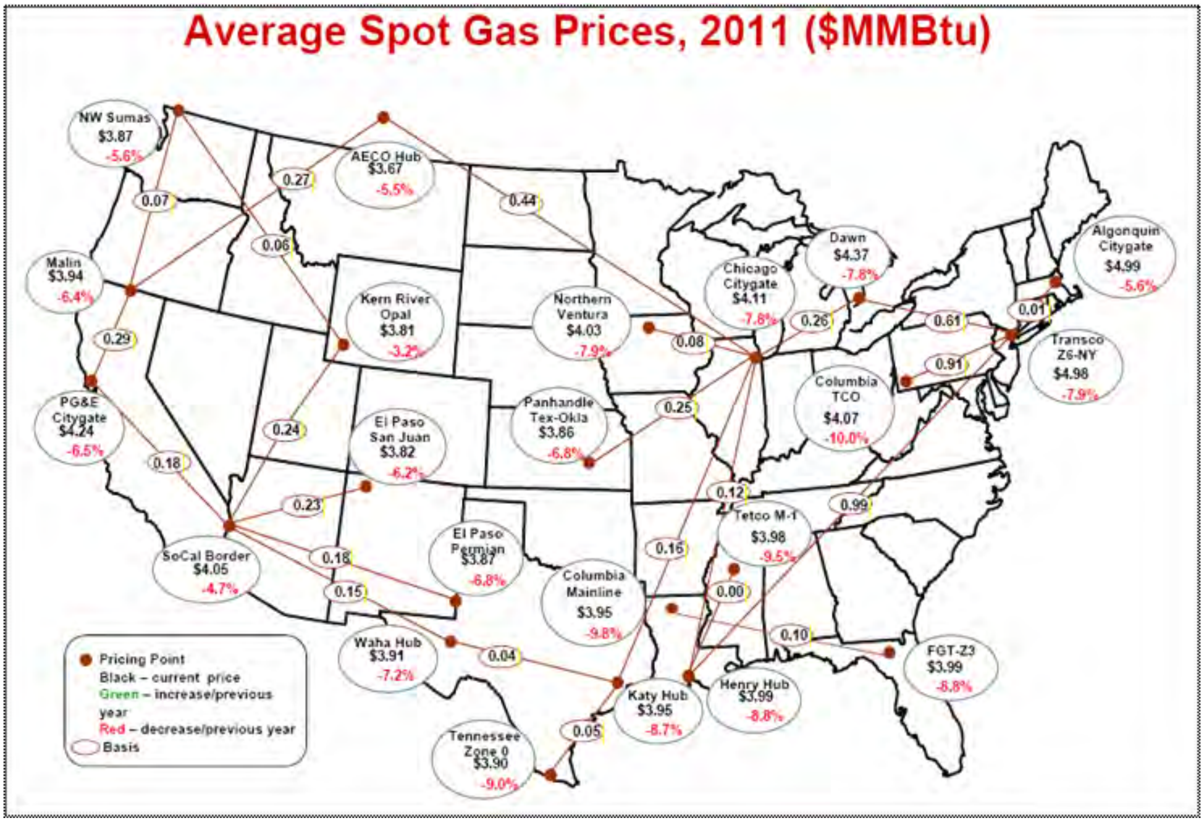


Source: California Energy Commission. For interstate pipeline tariff see http://passportebb.elpaso.com/ebbmasterpage/Tariff/OrgChart.aspx?code=EPNG&status=Tariff&pdftag=rsft1. For distribution rates see http://www.pge.com/tariffs/GRS.SHTML#GRS.

Figure 16 shows many of the major natural gas market hubs in the United States and some in Canada. The figure also shows average 2011 spot prices, and the percentage change from 2010. Almost all United States natural gas prices decreased from 2010 to 2011. Current prices would show a more dramatic decrease from 2010 prices. Since the beginning of 2012, natural gas has been trading in the $2/MMBTU range. The lines in **Figure 16** represent natural gas pipelines since natural gas market hubs need to be connected to pipelines to take delivery of and to transport natural gas. This figure does not have a line to represent the Ruby Pipeline, which came into operation in July 2011. Additional information on natural gas pipeline infrastructure is presented in Chapter 5.

A quick example of natural gas flowing from the Rocky Mountains, in Colorado, to California will help illustrate these different pricing locations. Natural gas from the Rocky Mountain supply area can be sold at the wellhead or transported for sale to another pricing point between the wellhead and the end user. Much of this natural gas is traded at the Opal Hub in Southwest Colorado. The Opal Hub is connected to a few interstate natural gas pipelines, El Paso Pipeline being one that transports natural gas to California. Natural gas from the Opal Hub can travel west on the El Paso Pipeline and eventually ends up at the southern border of California.

Figure 16: Major North American Natural Gas Market Hubs



Source: http://www.ferc.gov/market-oversight/mkt-snp-sht/2012/03-2012-snapshot-west.pdf.

Natural gas can then enter California through Topock, Arizona. Topock is one of the PG&E and SoCal Gas Company border price points. Natural gas from these border locations can then flow into the California backbone and transmission systems. The backbone and transmission systems provide natural gas to commercial and industrial end users, as well as electric generation facilities.[92] From the California transmission system, natural gas can flow into the PG&E Citygate or the Southern California Gas Company SoCal Gas Citygate pool pricing points.[93] Beyond these pricing points is the distribution system, where mostly residential and small commercial customers receive natural gas for consumption. The

92 The backbone pipeline system is generally larger than the transmission and distribution systems. Backbone level customers, such as electric generators, typically use much more gas than transmission or distribution level customers and so are able to receive gas straight off the backbone system.

93 The citygate price is the price paid by a natural gas utility when it receives natural gas from a transmission pipeline. "Citygate" is used because the transmission pipeline often connects to the distribution system that supplies a city.

farther the natural gas has to travel to its destination, the higher the transportation costs. For example, natural gas at the PG&E Citygate will almost always cost more than natural gas at the California border market hubs.

Real-time variability of natural gas prices occurs in the market. However, quite often natural gas prices are reported as averages over a period. The tradeoff is that information about real-world daily or seasonal volatility is lost. Volatility is still there in the form of expected seasonal variations and unexpected variations due to unusual events. **Figure 17** illustrates how averaging prices over a longer period can lead to a different impression than reporting prices over a shorter term. The graph shows three years of California monthly and annual average Citygate prices for the period 2007 – 2009. The annual average price for 2008 masks the considerably higher July 2008 peak price (as it does the November 2008 low).

Figure 17: California Average Citygate Prices

Source: U.S. EIA.

Recent and Historical Natural Gas Prices

Natural gas prices were increasing steadily up to 2008, when they began to drop. The average monthly Henry Hub spot price increased more than 200 percent from January 2000 to January 2008, with an annual average increase of about 29 percent per year. From January 2009 to April 2012, Henry Hub spot prices decreased by 64 percent, with average annual decreases of 19 percent. Natural gas is a heavily traded commodity. **Figure 18** illustrates the volatility inherent in this market. Over the last decade, natural gas prices have spiked several times, including the winter periods of 2000/2001 and February 2003, when natural gas prices reached $10/MMBtu and $18/MMBtu, respectively.

A number of factors can explain the winter 2000/2001 price spike. Cold weather conditions caused natural gas demand for heating to be relatively high, and there were low natural gas storage levels heading into the winter heating season. The summer of 2000 was warmer than normal, causing more natural gas to be withdrawn from storage for electric generators to meet air-conditioning load. A pipeline near Carlsbad, New Mexico, owned by El Paso Natural Gas, ruptured in August 2000, causing natural gas deliveries into California to drop by 400 MCF/d, or 6 percent of California's demand. This event, which resulted in California losing some of its supplies, led to more natural gas being withdrawn from storage, which in turn put additional upward pressure on price. Some industry stakeholders and regulators pointed to market manipulation as another factor contributing to the price spike.

The price spike of February 2003 was largely weather-related. The 2002/2003 winter was colder than normal for much of the United States, causing higher heating demand and thus more natural gas being drawn from storage. A cold storm came to the United States in February 2003, bringing very cold temperatures to the producing areas. The severe cold temperatures caused some natural gas wells to freeze off, reducing production and hence the amount of supply available to meet demand. By March 2003, natural gas storage levels were 20 percent less than the same period in 2001.[94]

Another price spike occurred in September 2005 when hurricanes Katrina and Rita caused natural gas production in the Gulf Coast to decline substantially. At the time, the price of natural gas increased from $5 to $15/MMBtu.[95] In summer 2008, another price spike occurred, with June 2008 natural gas prices reaching $13/MMBtu. Since then, prices have declined over the next 16 months with the exception of one relatively mild price spike of $7.51/MMBTU on January 8, 2010.[96]

Since July 2011, natural gas prices have been declining at a steeper rate than the preceding 16 months. High natural gas production levels, along with a mild winter and record storage levels, are major contributors to the low natural gas price environment that exists today. This is illustrated by **Figure 18**. In response to low natural gas prices in recent months,

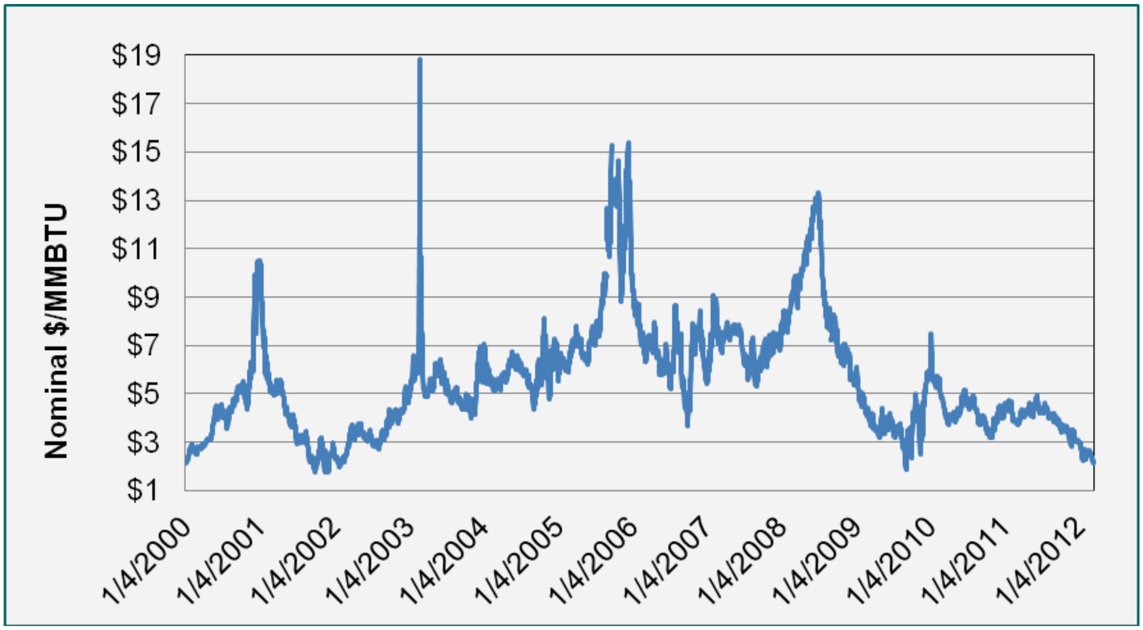
94 Since 1997, the lowest level of working gas in storage for the lower 48 occurred in March 2003; the second lowest level occurred in March 2001. See http://www.eia.gov/dnav/ng/ng_stor_wkly_s1_w.htm.

95 For more on natural gas price volatility and price spikes over the last decade see R. Roesser, *Natural Gas Price Volatility*, California Energy Commission, June 2009. See http://www.energy.ca.gov/2009publications/CEC-200-2009-009/CEC-200-2009-009-SF.PDF.

96 For more on natural gas price spikes over the last decade, see http://www.energy.ca.gov/2009publications/CEC-200-2009-009/CEC-200-2009-009-SF.PDF.

industry stakeholders such as Raymond James and Merrill Lynch, as well as the U.S. EIA recently reduced their short term natural gas price forecasts citing strong supply and low demand as a major factor.[97]

Figure 18: Henry Hub Daily Spot Prices



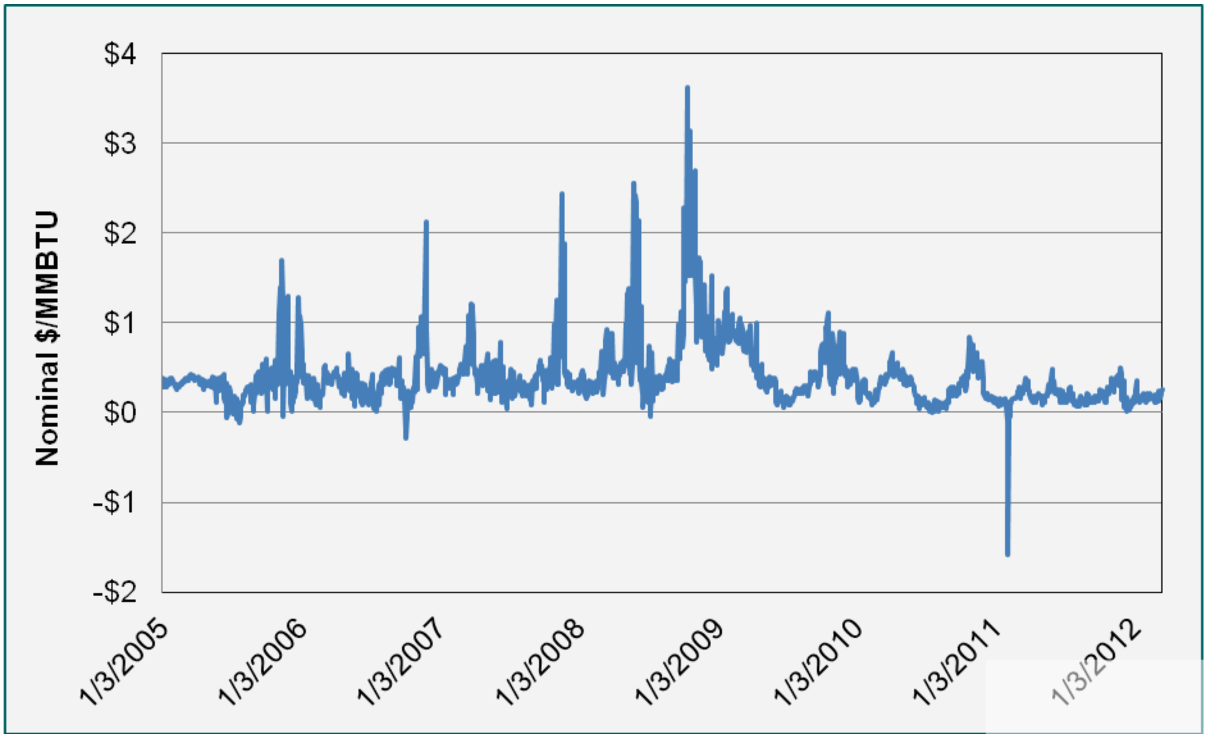
Source: http://intelligencepress.com.

Basis Differentials

Natural gas prices differ at different points in the United States. As described, additional costs for transportation and compression, as well as pipeline congestion, are added to the price of natural gas as it travels to consumers. **Figure 19** shows the daily spot price differential, or basis differentials, between the PG&E Citygate price and the Southern California border price for PG&E. With few exceptions, the Citygate price, which is closer to end-use customers, is at a premium to the border price. Over the last year, this basis differential has stabilized, and the PG&E Citygate price is at a lower premium than most of the historical prices over the last six years. It is uncertain whether this pattern of a low and stable basis differential will continue in the future as changing supply/demand dynamics will most likely cause some shift in basis differentials.

97 See http://money.cnn.com/2012/01/11/markets/natural_gas_prices/index.htm, and http://blogs.star-telegram.com/barnett_shale/2012/02/raymond-james-investment-firm-reduces-forecasted-natural-gas-price-to-250-for-2012.html.

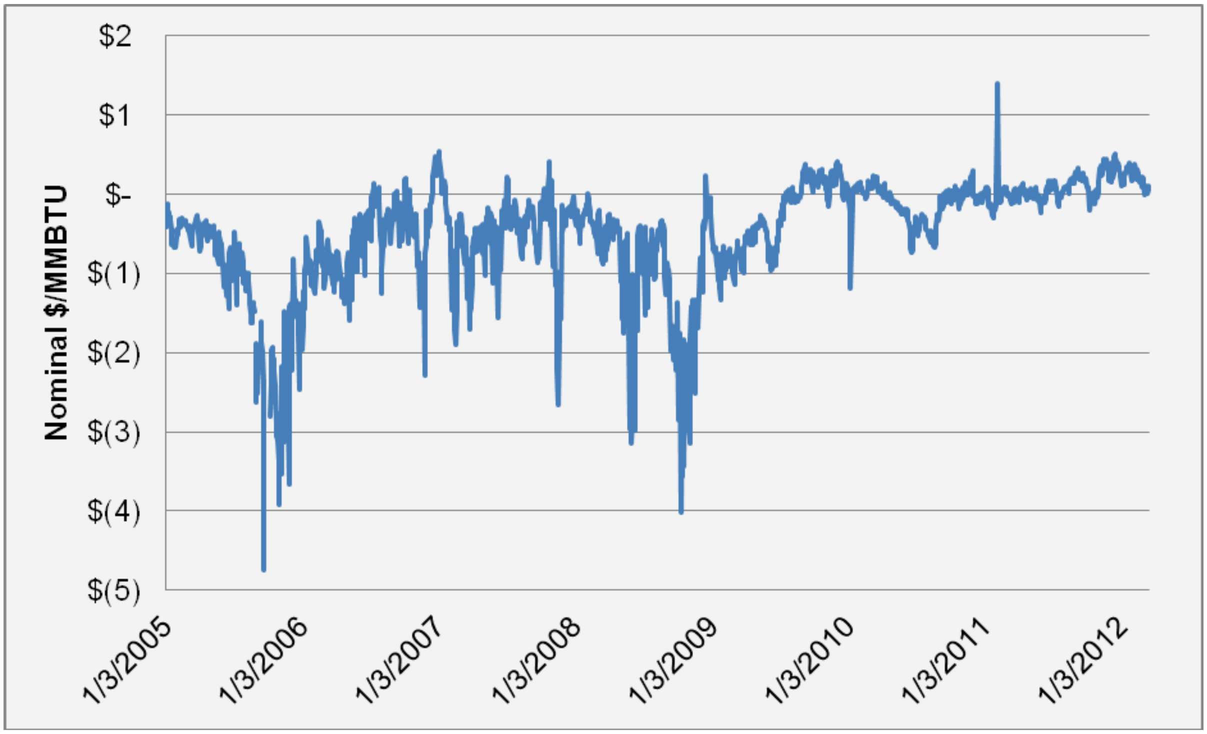
Figure 19: Daily Spot Price Differential PG&E Citygate Price Minus SoCal Border Price



Source: http://intelligencepress.com.

Figure 20 shows the differential between the Henry Hub spot price and the Southern California border spot price. Before 2009, Henry Hub spot prices were higher than natural gas prices in California. However, between August and September 2009, California natural gas prices started trading at a premium to Henry Hub. One explanation for this reversal is the completion of the Rocky Mountain Express (REX) Pipeline in November 2009. The pipeline now delivers natural gas to eastern Ohio from northwestern Colorado, increasing competition for natural gas in the Rocky Mountain area, and thus pushing prices up, including prices for natural gas flowing into Southern California. Over the last 12 months, this basis differential has remained relatively stable and close to parity. The abundance of shale gas supplies, discussed in Chapter 2, and the REX Pipeline discussed earlier are two drivers of this recent basis differential trend.

Figure 20: Average SoCal Border Price Minus Henry Hub Price



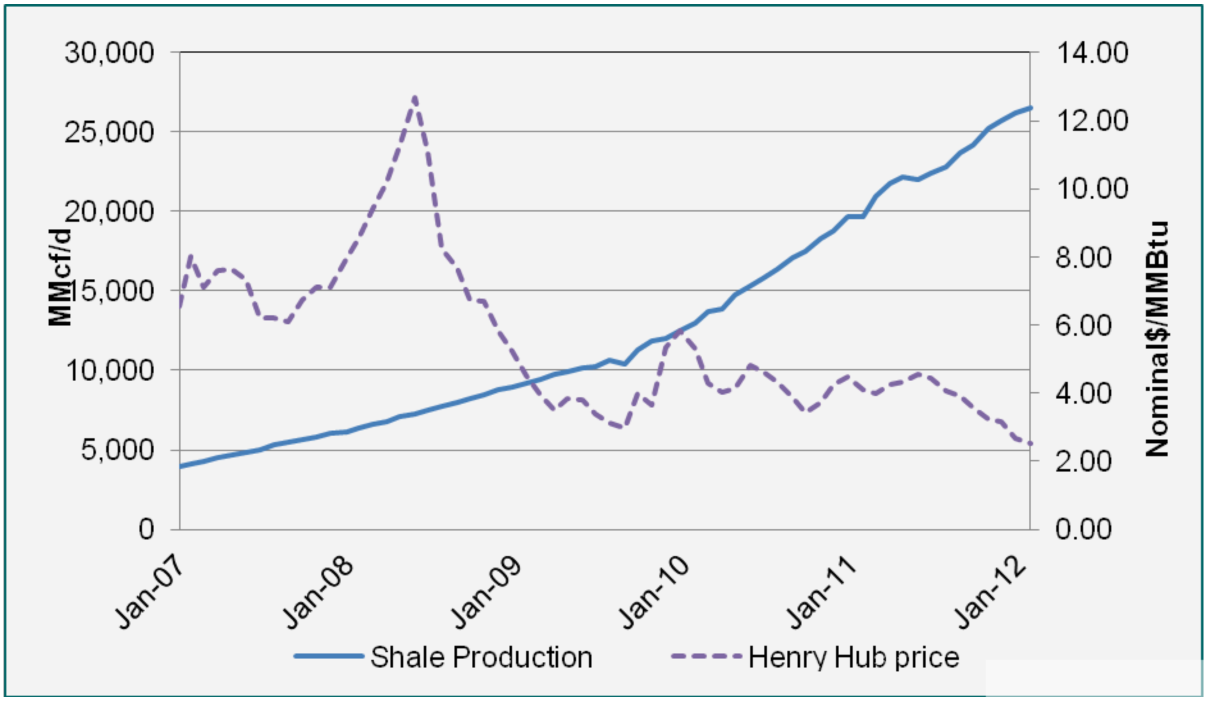
Source: http://intelligencepress.com.

Figure 21 plots monthly shale gas production from six major shale areas in the Lower 48 against average monthly Henry Hub spot prices.[98] As the supply of shale gas has increased, natural gas prices have decreased. There is significant uncertainty about whether this trend of increasing production from shale and decreasing prices can continue. It is not clear how currently low natural gas prices will affect production going forward. Some production companies, such as EnCana and Chesapeake Energy, have been discussing shutting in production and/or moving production wells from dry natural gas areas to more liquid-rich plays.[99]

98 The six major shale areas are the Barnett, Woodford, Fayettville, Haynesville, Eagle Ford, and the Marcellus.

99 Liquid-rich natural gas plays (natural gas formations that contain crude oil and natural gas liquids such as propane, ethane, and butane) are currently more attractive than dry gas plays that only produce gas. The liquid rich plays are more economic because the price for natural gas liquids is many times higher than that of the gas itself. For more on this subject, please refer to in Chapter 2.

Figure 21: Monthly Major Shale Production and Monthly Average Henry Hub Spot Price



Sources: U.S. EIA (spot prices) and [http://www.lippmanconsulting.com for production (production)](http://www.lippmanconsulting.com).

There are several factors related to pipeline infrastructure that can affect natural gas prices. Pipeline constraints can restrict the amount of natural gas that reaches consumers and result in higher prices. New pipeline additions or expansions can change natural gas prices. For example, the Ruby Pipeline is bringing natural gas from the Opal Hub in Wyoming to Northern California at the Malin Hub in Oregon, increasing the supply of natural gas and lowering the price of natural gas for consumers in California. Since the Ruby Pipeline came on-line in July, natural gas prices in both Northern and Southern California have decreased more rapidly than during the previous 16 months. In fact, this decrease is more pronounced at the Malin pricing point than it is at the SoCal Border pricing point. The Ruby Pipeline transports natural gas to Northern California, which also receives some of its natural gas from Canada. The Ruby Pipeline has caused more natural gas-on-gas price competition in Northern California (between Canadian natural gas and natural gas from the Opal Hub). Thus, although both Northern and Southern California prices have decreased as a result of Ruby, Northern California prices have decreased more than Southern California prices. Recent pipeline additions and their influence in creating competition in natural gas markets, which drive down prices, are discussed in greater detail in Chapter 5.

Natural Gas Pricing Issues

Several emerging issues are likely to influence natural gas prices going forward. These include new regulation of financial markets for natural gas, the cost of utility pipeline safety enhancement, producer responses to sustained low prices, and the potential for United States exports of natural gas as LNG. These issues are discussed in the following sections.

Regulation of Financial Markets for Natural Gas

The effects of recent financial regulations on natural gas prices, in particular the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), remain unclear for reasons described later. The Dodd- Frank Act could include higher costs to purchase swaps and options, and higher costs for compliance. The impacts may also include higher collateral requirements, and observers may see fewer market makers. There is at least some concern that the requirements could make hedging too expensive for energy commodity end users, depending on the final implementing regulations from the Commodity Futures Trading Commission (CFTC). The following discusses the context of regulation of financial natural gas transactions and summarizes key aspects of the Dodd-Frank Act and why these effects may occur.

Natural Gas Futures

Futures trading for natural gas can either be a physical trade (trading the physical natural gas) or a financial trade. A financial trade can be a hedge against future price volatility and the risk of price changes; it can also be based on speculation to profit from price movements. The CFTC defines a commodity futures speculator as "a trader who does not price hedge but who trades just to receive a profit through the successful anticipation of outright price movements or through relative price movements." Speculators take large risks, especially with respect to anticipating future price movements, in the hope of making quick, large gains.[100] There is significant debate on how speculators affect financial commodity markets and natural gas prices. Appendix B provides a more detailed discussion of the role of natural gas futures and their regulation.

Some analysts argue that natural gas consumers benefit from competitive wholesale natural gas markets, both physical and financial. They argue that good speculation in the futures market tends to have a price stabilizing effect, promoting competition and producing accurate price signals of supply and demand. The analysts who view the futures market and speculators as entities that have a stabilizing effect on prices generally assert that speculation is neither excessive nor manipulative, and additional regulation of the futures market would reduce the liquidity in which financial hedging instruments are traded.

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100 See http://www.investopedia.com/terms/s/speculator.asp.

Other analysts and industry stakeholders believe that, although good speculation has its place in commodity markets, excessive speculation and manipulation are more commonplace in the futures market. Excessive speculation can lead to price bubbles through a herding instinct, and market manipulation can cause price changes that do not accurately reflect supply-and-demand interactions. Analysts and industry stakeholders assert that the recent trend of more noncommercial traders entering the futures market has led to excessive speculation and price volatility. They believe that regulating the futures market will help to reduce excessive speculation, bubbles, and the herding instinct rather than scare away "good" speculators.

Financial regulation of natural gas markets first came about in response to the 2000/2001 energy crisis. One aspect of the crisis was that certain energy firms were found to be making false trades on the futures market and gaming the system by withholding supply. More recently, analysts and stakeholders raised concerns that the oil price spikes in June/July 2008 were the result of market manipulation. In response, the United States House of Representatives passed the Energy Markets Emergency Act of 2008, which directed the CFTC to use its authority to eliminate excessive market speculation, price distortion, excessive price volatility, or any other unlawful activity that prevents the market from accurately reflecting the forces of supply and demand for energy commodities. However, in early 2009, the CFTC released a report on the price spike of June/July 2008, concluding that supply-and-demand interactions caused the spike rather than speculation in the market. Despite the CFTC findings, lingering concerns about the role of speculation in energy markets have persisted.

In September 2008, the CFTC released a report on swap dealers and index traders. This report also stemmed from the crude oil price spike that occurred in June 2008, as well as public outcry about market manipulation causing the price spike.[101] Over-the-counter (OTC) swap markets do not have the same comprehensive regulation and oversight that the futures and options markets do. While this report did not find any evidence of market manipulation or excessive speculation causing the price spike, many of the recommendations from the report were intended to bring more transparency to the OTC swaps market.[102] Also, many of the recommendations would require more data reporting from the OTC swap markets. The majority of the recommendations became part of the Dodd-Frank Act.

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101 Many academic studies believe speculation at least partially caused commodity prices to spike in the summer of 2008. See http://www.cftc.gov/PressRoom/SpeechesTestimony/opachilton-41.

102 See http://www.cftc.gov/PressRoom/PressReleases/pr5542-08, and http://www.loe.org/images/content/080919/cftcstaffreportonswapdealers09.pdf.

The Dodd-Frank Act

The Dodd-Frank Act, which was signed into law on July 21, 2010, is intended to increase market integrity and accountability in financial markets while reducing market manipulation and other fraudulent actions by regulating the swaps, futures, and options marketplace with more robust oversight and transparency.[103] The intent of the Dodd-Frank Act is to prevent the kind of financial meltdown that was narrowly avoided in September 2008. Some of the key aspects of the bill that may affect financial energy markets include:

- Requiring public disclosure to the Securities and Exchange Commission (SEC) of payments made to the United States and foreign governments relating to the commercial development of oil, natural gas, and minerals.
- Requiring those engaged in the commercial development of oil, natural gas, or minerals to include information about payments they or their subsidiaries, partners, or affiliates have made to the United States or a foreign government for such development in an annual report and posting this information online.
- Requiring hedge funds and private equity advisors to register with the SEC as investment advisers and provide information about their trades and portfolios necessary to assess systemic risk. Data will be shared with the systemic risk regulator, and the SEC will report to Congress annually on how it uses this data to protect investors and market integrity.
- Raising the assets threshold for federal regulation of investment advisers from $30 million to $100 million, a move expected to significantly increase the number of advisors under state supervision. This will allow the SEC to focus its resources on newly registered hedge funds.
- Requiring the CFTC to adopt position limits for exempt commodities (for example, energy and metals) within 180 days of its enactment, and for agricultural commodities within 270 days. Some trading platforms, such as NYMEX, currently have some position limits through what are called *accountability levels*. The position limits in the Dodd-Frank act will cover more trading platforms and more financial commodities such as swaps and options currently not covered.
- Establishing position limits on 28 core physical-delivery contracts and their economically equivalent contracts, listed as “referenced contracts.” There are four energy contracts, including NYMEX Henry Hub Natural Gas.
- Requiring data collection and publication through clearinghouses or swap repositories to improve market transparency and provide regulators important tools for monitoring and responding to risks.

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103 Transactions that are hard to understand are not transparent and result in hidden risks, including counterpart risk that cannot properly be evaluated.

The bill requires new rules to be implemented within 360 days following enactment, which would have been July 16, 2011. However, in early July 2011, the CFTC voted to delay implementation to give more time to resolve disagreements about several of the new rules. There has been controversy over some of the implementing details, even talk in Congress about modifying the Dodd-Frank Act or pulling parts of it back. Rules on position limits have been further delayed; position limit rules for futures and swaps were delayed until October 2011, while position limits for derivatives were delayed until at least the end of March 2012. On April 18, 2012, the CFTC and the SEC jointly passed rules that defined swap dealers and related terms.[104] Definitions of other terms, including position limits, are expected by the end of this year. Spot month position limits for swaps will go into effect 60 days after the final decision. Nonspot month position limits will become effective after the CFTC has at least 12 months of data on swap transactions; the CFTC must then analyze these data to help determine the position limits. Looking at previous delays, it is possible that compliance of position limit rules will not go into effect until late 2012 or early 2013.

Financial entities, marketers, and some utilities generally claim that the Dodd-Frank Act will make hedging more expensive due to the collateral requirements associated with use of a clearinghouse, and the time and effort to report all swaps to the swap data repository. Some claim that fewer dealers will sell derivatives or be willing to serve as market-makers. Fewer deals being made equates to reduced liquidity in the market, and those marketers not making deals will not have their information reflected in the price of natural gas. The price discovery function of the market (which is the outcome price of many buyers and sellers in the market) may be hurt with reduced liquidity.

Others argue that the data reporting requirements are cumbersome and that hedging may become more transparent, but will also become more difficult. Smaller utilities may turn even more to outside entities to avoid the expense of trade capture and reporting systems. The exact effects will take time to evolve, but it seems reasonable to expect some effect on the pricing and availability of derivatives as the market adjusts to the new rules, higher collateral requirements, and maybe some new software requirements (for data reporting).

The Impact of Utilities' Pipeline Safety Enhancement Plans (PSEP)

On September 9, 2010, a PG&E high-pressured natural gas transmission pipeline, known as Line 132, exploded under a neighborhood street in San Bruno, California, killing 8 people and destroying 37 homes. The CPUC and the National Transportation Safety Board (NTSB) both launched investigations into the explosion. The Energy Commission's *2011 Integrated Energy Policy Report* provides additional details on the incident in San Bruno and its implications.

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104 See http://www.sec.gov/news/press/2012/2012-67.htm.

A key outcome of the investigations into PG&E's San Bruno pipeline explosion is new rules directing testing or replacement of pipelines for which the natural gas utilities have too little documentation of maximum allowable operating pressures. This includes pipelines in High Consequence Areas, generally urban areas where pipeline failure can have a high potential impact on people and property, as well as other pipelines built before 1970. Each of California's natural gas distribution utilities has filed a PSEP, which details the testing and replacement efforts and estimate costs. As previously mentioned, PG&E estimates a Phase I cost of $2 billion before including financing costs.[105] SoCal Gas estimates Phase I of its PSEP will cost $2.5 billion.[106] Some of the costs include making pipelines more "piggable," to allow use of in-line inspection tools as well as installing more remote-controlled and more automatic valves. In addition, utilities plan to upgrade the supervisory control and data acquisition systems and pursue efforts to notify and interact with first responders. Some of the new rules for establishing minimum allowable operating pressures on older pipelines are also being considered by the Federal Pipeline and Hazardous Materials Safety Administration and could be applied elsewhere in the United States.

The PSEPs aim is to upgrade or replace existing pipeline infrastructure to make it safer and more reliable. Ratepayers are expected to fund most of the utilities' PSEPs, although utility shareholders may also pay a portion of it. These PSEPs include timelines going out four years, and more importantly, impacts to ratepayers.[107] Rate impacts past the first four years have not been estimated by the utilities.

Preliminary estimates show that ratepayers will see a rate increase anywhere from $0.04/MMBTU to $0.52/MMBTU (between an 8 and 86 percent increase), depending on end-use customer class, as shown in **Table 4**. Residential, small commercial, and large commercial customers are expected to see a $0.52/MMBTU increase in their transportation rate, which equates to 8 percent, 12.4 percent, and 21 percent increases, respectively. Large commercial customers see a bigger rate increase (21 percent) than do small commercial customers, as they will both pay $0.52/MMBTU more. In addition, large commercial customers pay almost half of what small commercial customers pay for transportation.

Electric generation customers generally pay the smallest amount for the PSEP, although their percentage increase in transportation rates can be much higher as they pay a smaller amount for transportation compared to other customer classes. Transmission level and

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105 See http://www.pgecurrents.com/2012/02/28/pge%e2%80%99s-pipeline-safety-enhancement-plan-2-2-billion-or-5-billion/.

106 See http://www.socalgas.com/safety/pipeline-safety-enhancement-plan/faq.shtml and http://www.socalgas.com/regulatory/documents/r-11-02-019/Amended%20PSEP-12.2.11.pdf.

107 See PG&Es PSEP at http://docs.cpuc.ca.gov/efile/EXP/142983.pdf and SoCal Gas/SDG&E at https://www.pge.com/regulation/GasPipelineSafetyOIR/Pleadings/Joint/2012/GasPipelineSafetyOIR_Plea_Joint_20120110_226046Atch01_226047.pdf.

backbone level electric generation customers are expected see an increase in their transportation rates of $0.25/MMBTU and $0.02/MMBTU, or an 86.2 percent increase and 28.6 percent increase, respectively.

Rate increases shown in **Table 4** are all preliminary estimates, which the CPUC will need to approve before they become effective.[108]

Table 4: Estimates of Rate Impacts From PSEPs

All Rates in $/Dekatherm Unless Otherwise Specified			
PG&E	**June 2011 Transportation Rate**	**PSEP Addition**	**Percent Increase**
Residential	$6.50	$0.52	8.0%
Small Commercial	$4.18	$0.52	12.4%
Large Commercial	$2.48	$0.52	21.0%
Electric Generation - Transmission-Level Service	$0.29	$0.25	86.2%
Electric Generation - Backbone Level-Service	$0.07	$0.02	28.6%
SoCal Gas			
Average Residential Bill ($/Month)	$39.08	$2.82	7.2%
Core Commercial & Industrial	$3.15	$0.35	11.1%
Electric Generation - Distribution-Level Service	$0.39	$0.04	11.2%
SDG&E			
Average Residential Bill ($/Month)	$38.76	$2.83	7.3%
Core Commercial & Industrial	$2.49	$0.35	14.1%
Electric Generation - Distribution-Level Service	$0.42	$0.04	10.3%

Source: PG&E: http://docs.cpuc.ca.gov/efile/EXP/142983.pdf. SoCal Gas and SDG&E: http://sdge.com/sites/default/files/regulatory/PSEP-Overview-Briefing-9-19-11.pdf.

Short-Term Response to Lower Natural Gas Prices

The sustained low natural gas prices over the last year have led to some natural gas producers announcing cuts to natural gas drilling, particularly in the more dry natural gas plays. Both Chesapeake Energy and EnCana have publicly announced they will cut production in dry natural gas fields and focus more on NGL rich fields.[109] This switch to more liquids-rich natural gas fields is a result of low natural gas prices making dry natural gas fields uneconomic. The current high price of crude oil, presently more than $100 per barrel (bbl), makes NGLs more economic compared to natural gas.[110] The shift away from

108 Rates in **Table 4** have been converted to $/Dekatherm; the utilities usually report in $/Therms. 1 Dekatherm = 1 MMBTU.

109 See http://www.ogj.com/articles/print/vol-110/issue-2/general-interest/chesapeake-cuts-operated.html, and http://www.upstreamonline.com/live/article304142.ece.

110 NGL prices tend to track crude oil prices. See http://www.natgas.info/html/gascontracts.html.

dry natural gas fields is somewhat expected as recent breakeven price estimates for natural gas drilling are many times higher than the current level of spot prices for natural gas.[111]

There are a number of uncertainties about how natural gas producers will respond to low prices. For example, it is not clear how low natural gas prices need to get before producers actually cut production to a level that will have a material effect on natural gas prices. Producers are switching to wet natural gas plays, and the announced production cuts have had negligible effects on natural gas prices. There are additional uncertainties about what action producers will take if NGL prices fall. NGL prices could potentially fall if crude oil prices collapse or if demand for NGL drops due to a lack of demand in the petrochemical industry. Assuming that NGL prices drop low enough, producers could cut production in the more liquids-rich natural gas fields. If a situation arises where both NGL prices and natural gas prices are low, natural gas producers may focus more of their attention on United States LNG exports, which is already happening.

The Impact of United States LNG Exports on Natural Gas Prices

Low natural gas prices, along with the abundance of shale gas supplies, have some industry stakeholders calling for the United States to export LNG to other markets around the world. This possibility is attractive because other markets, such as Asia and Europe, are paying more than $14/ MMBTU and $9/MMBTU, respectively, for LNG.[112] Exporting LNG to other countries remains feasible as long as the price spread between domestic natural gas prices and prices in countries that would potentially import LNG from the United States remains large enough. The price spread in question needs to be wide enough for the United States to pay liquefying and transporting costs of the natural gas, as well as to make a profit.

In the early 2000s, the United States experienced a large amount of LNG imports. However, a decline of imports started in late 2007 and has persisted through 2011, largely due to the high LNG prices in the Asian markets that are attracting LNG cargoes. Asian and European markets have fewer sources of natural gas and are willing to pay higher prices than in North America. Additional details on the LNG facilities and imports are presented in Chapter 5.

Over the last few decades, there has been a strong price relationship between crude oil and natural gas prices. In the United States that was due to fuel switching between natural gas and residual fuel oil (RFO). Fuel switching is not as prominent as it once was and, as a result, does not drive this relationship as much as it did historically.[113] Another factor

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111 See http://globalchange.mit.edu/files/document/MITJPSPGC_Reprint_12-1.pdf, p. 42.

112 See http://www.ferc.gov/market-oversight/mkt-snp-sht/2012/02-2012-snapshot-west.pdf.

113 In implementing the Clean Air Act of 1990, the U.S. EPA reduced the use of RFO in the United States dramatically in the 1990s. See http://www.epa.gov/airquality/peg_caa/index.html.

contributing to a strong link between crude oil and natural gas price is that both of these fossil fuels have similar geological characteristics, employing much of the same drilling technology and equipment. In addition, many of the large energy companies drill for both fuels, and historically, both fuels have at times been produced from the same geologic formations. A final influence in recent years is associated with the emergence of the international LNG market. Many LNG contracts are generally indexed to oil prices.

In the United States, this relationship has weakened greatly since the end of 2008, as fewer cargos of LNG are delivered to the United States. Shale supply has shifted the supply/demand dynamic and may also be partly responsible for weakening the crude oil and natural gas price relationship. One of the concerns about the United States becoming a major exporter of natural gas is that it could expose natural gas prices to the vagaries of the international oil market. Appendix B presents a more detailed discussion of the crude oil and natural gas price relationship.

There are varying opinions on whether exporting LNG is beneficial for the United States economy or in the national interest. Some experts indicate that the ability to export LNG would be healthy for the United States natural gas industry and would support domestic supply development over the long run. Essentially, it would provide the United States with the opportunity to capitalize on basis differentials in the LNG world market. The option to export LNG adds flexibility for companies operating in a market that is currently oversupplied by providing access to new or additional customers in international markets. However, some other experts argue that the option to export LNG would expose the United States to the world's LNG price fluctuations and would drive up the price of domestic natural gas.

Some research has been conducted on the potential natural gas price impacts of the United States exporting natural gas.[114] The U.S. EIA study finds that United States natural gas Henry Hub prices are $0.60/MMBTU higher, on average, from 2016-2035 with 6 billion cubic feet per day (Bcf/d) of LNG exports. The Deloitte study finds that the Henry Hub price, on average, will increase by $0.22/MMBTU over the same period with 6 Bcf/d of LNG exports. The RBAC, Inc., study had the largest Henry Hub natural gas price increase of $1.33/MMBTU over the same time period assuming 6 Bcf/d of LNG exports.[115]

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114 See "*Effect of Increased Natural Gas Exports on Domestic Energy Markets*," at http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf, and "*Using GPCM to Model LNG Exports from the United States Gulf Coast*" at http://www.rbac.com/press/LNG%20Exports%20from%20the%20US.pdf, and "*Made in America, The Economic Impact of LNG Exports From the United States*" at http://www.deloitte.com/assets/Dcom-UnitedStates/Local%20Assets/Documents/Energy_us_er/us_er_MadeinAmerica_LNGPaper_122011.pdf.

115 See http://www.rbac.com/.

Much uncertainty exists in how United States LNG exports will affect domestic natural gas prices. The previous studies illustrate this with their wide range of potential LNG induced price impacts (from \$0.22/MMBTU to \$1.33/MMBTU). First, it is hard to predict what the natural gas price spread will be between domestic and foreign prices; this price spread determines the attractiveness of exporting LNG and how much LNG is ultimately exported. Also, the United States may need to compete with other countries, such as Australia, that wish to export LNG. If other countries besides the United States are exporting LNG, this increases natural gas-on-gas price competition and would act to lower the price the United States receives for its LNG. The level of natural gas demand in the United States may also affect how much LNG is exported. Higher natural gas demand in the United States can cause domestic prices to increase, in turn reducing the price spread between domestic natural gas prices and foreign LNG import prices.

All of the factors discussed above can affect the price spread of domestic natural gas and natural gas in other countries. Once again, this price spread is a major factor in the feasibility of United States LNG exports.

CHAPTER 4:
Natural Gas Demand Trends

Demand for natural gas in the United States has remained relatively flat over the last decade, with the exception of growth in the electric generation sector. Natural gas is gaining share in most United States fuel markets due to increased low-cost supplies and a versatile and extensive North American pipeline and local distribution system to deliver those supplies. However, increasing energy efficiency has cushioned the growth of natural gas consumption in the residential, commercial, and industrial sectors. On the demand side, policy developments in renewable energy, GHG, and other environmental initiatives are increasing natural gas demand because it is the cleanest of the fossil fuels. Environmental policies are driving a shift from coal to natural gas for electric generation. Going forward, natural gas demand will be influenced by the need for natural gas-fired generation to integrate increasing amounts of intermittent renewable resources and to displace coal generation.

Four major end-use sectors consume all but a fraction of natural gas supplied to North American markets — the residential, commercial, industrial, and electric power or generation sectors. The rest is used in the production and transmission of natural gas from wellhead to consumer. These sectors are recognized as economically and demographically discrete because their primary economic activities are distinct. The primary residential sector activity is housing, the primary commercial sector activity is trade in goods and services, the primary industrial sector activities are manufacturing, construction, and mining, and the primary electric generation sector activity is producing electricity.

Factors that affect California demand for natural gas in each sector include:

- Residential sector: recent historical demand for natural gas, population, natural gas price, income, and cold weather.
- Commercial sector: recent historical demand for natural gas, income and natural gas price, population, and cold weather.
- Industrial sector: recent historical demand for natural gas, natural gas price, industrial production, and cold weather.
- Electric generation sector: recent historical demand for natural gas, coal cost, natural gas cost, availability of hydroelectric generation, and hot weather.[116]

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116 The demand factors identified here are applicable to California natural gas markets; therefore, they differ somewhat from those identified in the *2011 Natural Gas Market Assessment: Outlook.* (CEC-200-2011-012-SD) The factors identified in the *Outlook* are applicable to modeling the United States' natural gas markets.

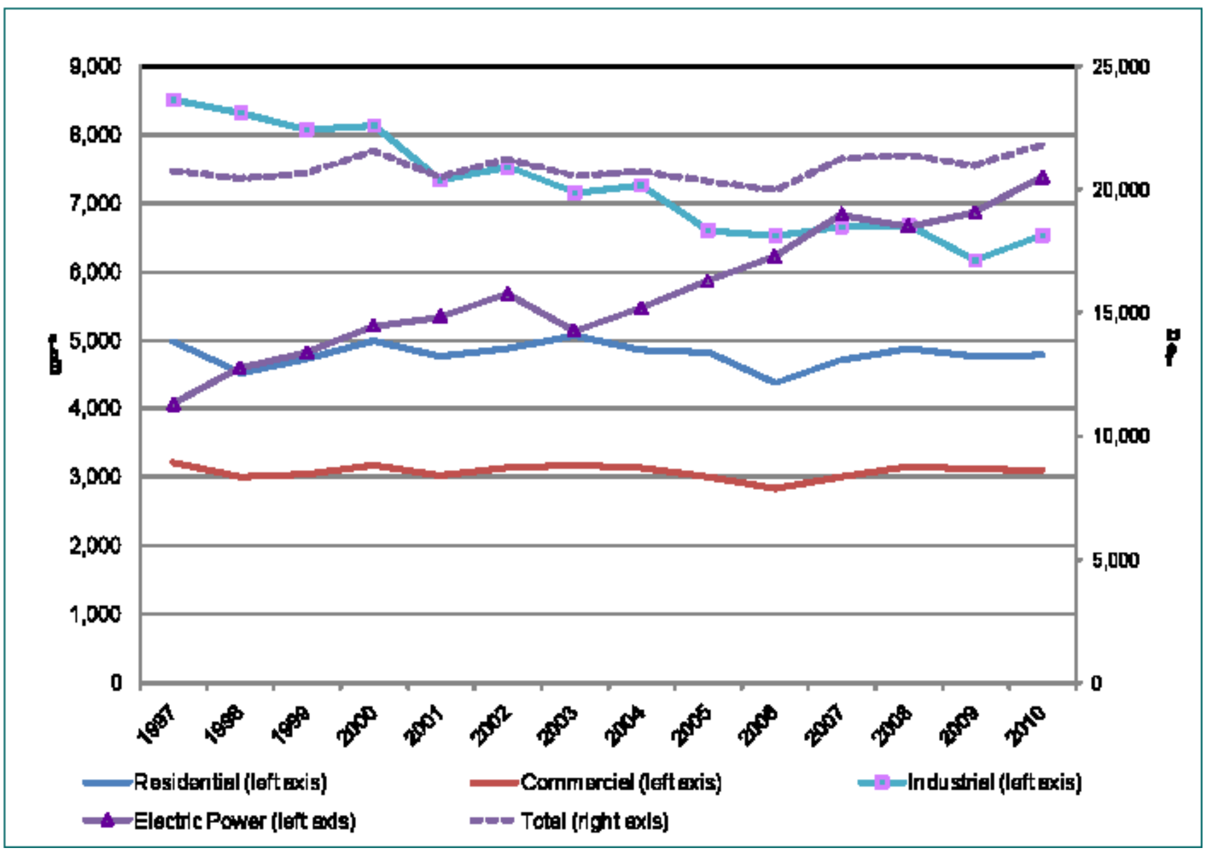
This chapter provides a review of recent market conditions and policy development impacts, plus other key trends and factors, such as the economy, demographic changes, and weather, all of which influenced natural gas demand (or consumption) over the past decade. These trends also provide indications on how natural gas demand might change in the next few years.

General Natural Gas Demand Trends

United States Natural Gas Demand Trends

The residential, commercial, industrial, and electric generation sectors account for 92 percent of total United States natural gas consumption. The remainder is consumed in motor vehicle fueling; in well, field, and lease operations; and as a fuel in natural gas stripping and processing plants, in compressor stations, and in other pipeline and distribution operations. **Figure 22** shows annual totals for the four major United States natural gas-consuming sectors, plus aggregate United States demand

Figure 22: United States Major Sector and Total Annual Natural Gas Demand, 1997 – 2010 (Bcf)



Source: U.S. EIA, *Natural Gas Monthly*, February 2012.

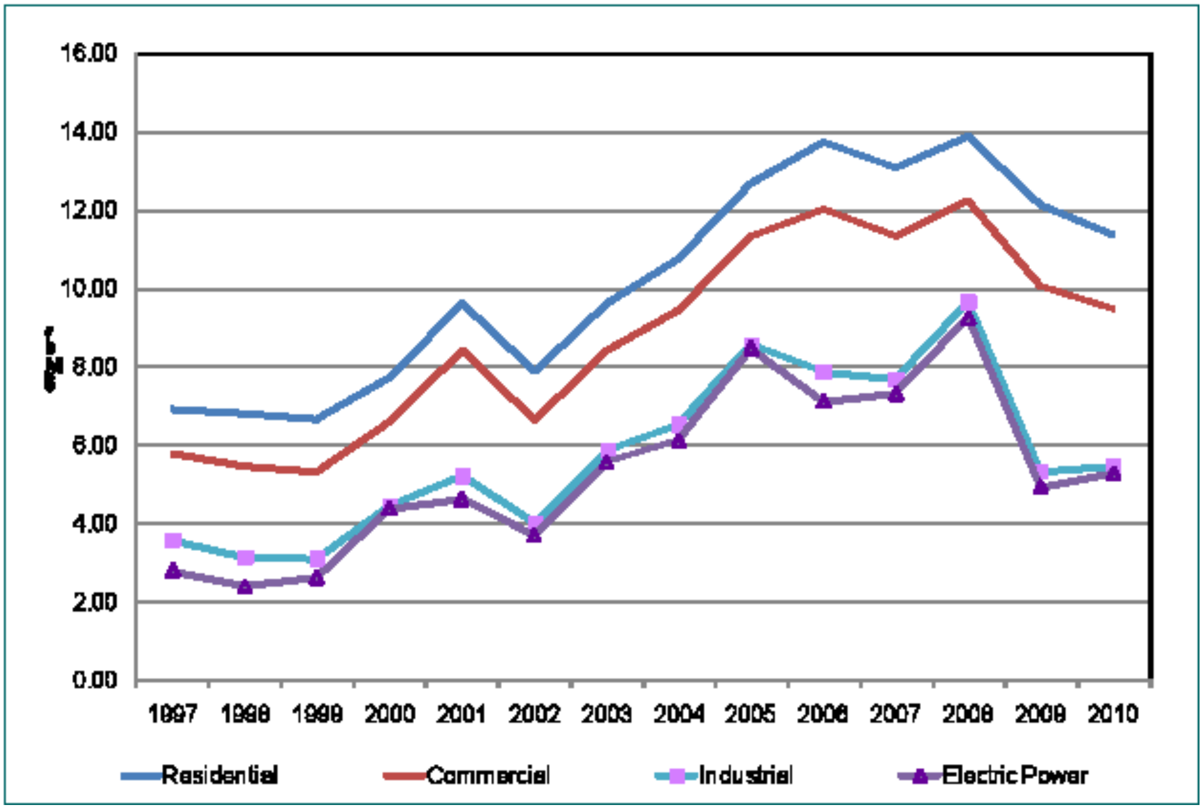
from 1997 to 2010. Residential, commercial, and total natural gas demand remained relatively flat over the period. Industrial sector natural gas demand decreased 23 percent. However, in the electric generation sector, natural gas demand increased 82 percent, exceeding industrial sector natural gas demand for the top rank in 2007. [117] In addition to discharging only about half the GHG and criteria pollutant emissions of coal-fired plants, natural gas-fired generation also enjoys lower capital and operation and maintenance costs than coal-fired or nuclear power plants. As a result, there have been major investments in natural gas power plants throughout the nation over the last decade.

As with many other commodities, nominal prices for natural gas delivered to all four sectors experienced a substantial increase through the same period. Looking at national averages between 1999 and 2010, residential prices nearly doubled. Industrial and electric generation sector prices more than doubled from 1999 to 2008 before the latter sectors' prices gave up most of that advance beginning in 2008.[118] Because price is a major factor influencing natural gas demand, the rising prices charted in **Figure 23** tend to depress consumers' demand. However, as the trends in **Figure 22** show, rising prices do not necessarily translate into demand reductions, only that prices exert a countervailing influence on demand.

117 U.S. EIA, *Natural Gas Monthly*, February 2012, Tables 12, 13, 14, 15, and 16.

118 U.S. EIA, *Natural Gas Monthly*, February 2012, Tables 18, 19, 20, and 21.

Figure 23: Major Sector Average United States Natural Gas Delivered Prices (Nominal $/Mcf)



Source: U.S. EIA, *Natural Gas Monthly*, February 2012.

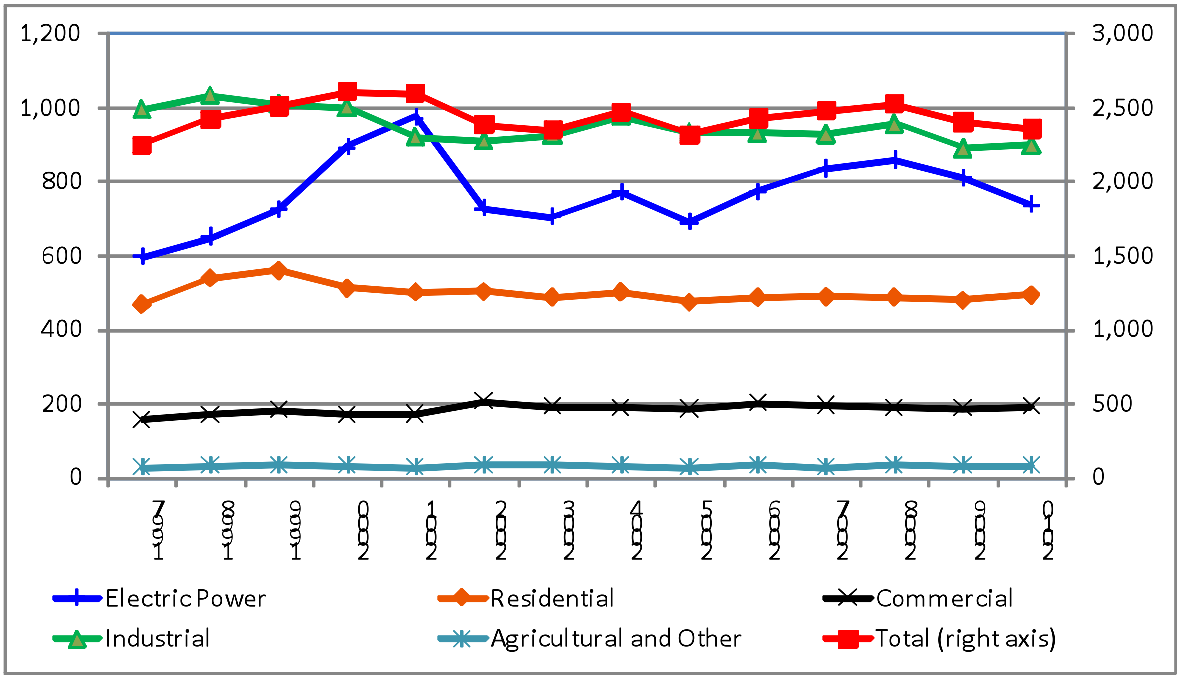
California Natural Gas Demand Trends

California aggregate demand for natural gas grew only slightly over the past decade, as shown in **Figure 24**. California residential and industrial demand is relatively flat while commercial demand increased moderately. California commercial sector natural gas demand rose 22 percent between 1997 and 2010. Four of the five largest natural gas-consuming subsectors — health care, restaurants, education, and hotels — saw rising demand over the period. The most notable contrasts between United States and California sector demand trends, as shown in **Figure 24**, are the falling United States and flat California industrial sector natural gas demand. One likely reason for the contrast between the flat California demand and the falling United States industrial natural gas demand is the fact that California industrial gross state product (GSP) more than doubled, while United States industrial gross domestic product (GDP) is mostly flat.[119] While the United States industrial sector natural gas demand fell, other fuels were not substituted in its place. This suggests

119 Bureau of Economic Analysis (U.S. Department of Commerce), *National Income and Product Accounts*, February 29, 2012, at http://www.bea.gov/regional/downloadzip.cfm.

that less natural gas-intensive industrial activities replaced energy-intensive production, or that energy-efficient technologies or other measures were implemented.[120]

Figure 24: California Natural Gas Demand by Sector, 1997–2010 (Bcf)



Source: California Energy Commission, *Quarterly Fuel and Energy Report (QFER).*

California electric generation sector demand spiked early in the last decade, which was caused largely by the economic expansion driven by the information technology subsector, followed by the 2000/2001 energy crisis and an economic downturn. There is an increasing trend in the United States electric generation sector natural gas demand, compared to the relatively flat demand from California's electric generation sector. The 2007 to 2009 recession appears to have had only a small impact on demand in any of the United States or California sectors. However, falling natural gas prices, beginning in late 2008 and continuing to the present, may have increased demand somewhat.[121]

120 U.S. EIA, *Annual Energy Review,* 2010, Table 2.1d, Figure 2.1b.

121 **Figure 24** shows gas demand data from Quarterly Fuel and Energy Report (QFER) and other California Energy Commission (Energy Commission) sources, which, unlike the U.S. EIA four-sector method, disaggregate total California gas demand into residential, commercial, industrial, agricultural, and other sectors.

While natural gas vehicle fueling accounts for less than 1 percent of both the United States' and California natural gas demand, this market is expected to enjoy sizable growth in California due to federal, state, and local regulations and incentives covering the purchase and operation of natural gas vehicles.

California natural gas demand trends also differ from United States trends in part due to differing commercial and industrial sector definitions between federal and state energy databases. This report uses U.S. EIA energy data for its analysis of United States' markets, and the Energy Commission's QFER, and related databases for its analysis of California markets. One example of differing definitions is that the U.S. EIA includes natural gas used in crop and livestock production, and forestry and fisheries in the industrial sector, while QFER includes these activities in a separate agricultural sector. Also, the U.S. EIA separated natural gas used in motor vehicle fueling from the commercial sector beginning in 1997; the Energy Commission instead relies on the utility-produced *California Gas Report* to account for this demand.[122]

There are other factors that account for daily, weekly, and monthly variations in natural gas demand. Weather exerts a strong seasonal influence that is reflected in monthly or weekly data but is not visible in annual demand data charted in **Figure 24**. These factors, including the influence of the weather, are discussed in additional detail in the following sections.

Natural Gas Demand Trends by Sector

Residential and Commercial Sector Natural Gas Demand

As previously discussed, the United States residential and commercial sector natural gas demand over the past decade was relatively flat. The United States housing boom of the past decade could have led to an increase in the demand for natural gas to fuel furnaces and other space-heating equipment, especially given the increasing preference for large tract homes. The larger floor spaces of these homes might be expected to require more heating fuels to maintain desired temperatures than smaller homes, everything else being equal. However, year-over-year losses in United States residential per-customer consumption in all but a few years since 1987 were a result of several factors, including: [123]

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122 California's natural gas utilities collaborate to prepare a biannual *California Gas Report* in compliance with CPUC Decision D.95-01-039. See http://www.pge.com/pipeline/library/regulatory/cgr_index.shtml.

123 U.S. EIA, *Trends in U.S. Residential Natural Gas Consumption*, 2010.

- Improvements in home construction energy efficiency standards and increased penetration of these standards in those markets. Nationally, homes built between 1990 and 2005 consumed 25 percent less natural gas for space heating than homes built before 1990.
- Efficiency enhancements in space-heating equipment and other natural gas appliances account for more than half of the reduction in per-customer demand since 1990.
- An increasing share of natural gas customers who do not use natural gas as their primary space-heating fuel, preferring electricity, heating oil, propane, wood, or other fuels instead.
- Population migration from colder to warmer regions.
- Rising prices of natural gas.

California residential natural gas demand was also relatively flat between 1997 and 2010, as shown in **Figure 24**. California commercial sector natural gas demand grew moderately over the same period. One major factor affecting natural gas demand for residential and commercial sectors in California is energy efficiency improvements. Several other factors affect natural gas demand for these two sectors, including weather, population, personal income, and other economic trends. These are discussed in the following sections.

Energy Efficiency Efforts

California has for decades led the nation in the development and implementation of the most progressive residential and commercial sector building and appliance energy efficiency standards and programs. Energy efficiency has remained the resource of first choice since the state implemented a loading order of energy resources with energy efficiency at the top in the *Energy Action Plan* (*EAP*), adopted in 2003. One result of this commitment to energy efficiency is that California has the lowest per-capita energy demand of all 50 states. California per-capita electricity demand, unlike the United States per-capita electricity demand, has been flat since the late 1970s. While energy efficiency is not the principal factor contributing to this progress, it is a major influence. Natural gas-fueled space heating, water heating, cooking and drying equipment is favored because their full fuel cycle energy efficiencies are nearly three times the efficiencies of electric alternatives. Statewide, 96.4 percent of homes have natural gas service in addition to electric service; the remaining 3.6 percent of homes do not have natural gas service.

Natural gas residential and commercial sector demand reductions from appliance and building standards, utility and public agency programs, price, and other market effects are estimated in 1990 at 18.8 percent, in 2000 at 24.5 percent, and in 2010 at 28.4 percent.[124] Estimates of natural gas demand savings achieved through California Code of Regulations Title 20 Appliance Standards and Title 24 Building Standards are shown in **Table 5**.

Table 5: Estimated Natural Gas Savings From Building and Appliance Standards: *Revised California Energy Demand Forecast 2012-2022* Mid Demand Scenario

Consumption Savings by Sector (Bcf)							
	Residential			Commercial			
	Title 24 Building Standards	Title 20 Appliance Standards	Total	Title 24 Building Standards	Title 20 Appliance Standards	Total	Total Standards
1990	70.50	66.22	136.72	3.41	3.02	6.43	143.15
2000	128.73	119.29	248.02	6.82	6.13	12.95	260.97
2010	166.61	147.43	314.04	10.61	9.25	19.87	333.91
2015	*179.86*	*159.80*	*339.65*	*12.66*	*11.20*	*23.86*	*363.51*
2020	*197.29*	*170.41*	*367.70*	*15.19*	*13.24*	*28.43*	*396.13*
2022	*203.81*	*174.40*	*378.22*	*16.16*	*13.93*	*30.09*	*408.31*

Source: California Energy Commission.

Residential sector savings estimated in **Table 5** account for much larger shares of total residential natural gas demand than the shares of commercial sector savings. Residential standards account for natural gas demand savings of 21 percent in 1990, 33 percent in 2000, and 39 percent in 2010. Commercial standards account for demand savings of 3.8 percent in 1990, 7.0 percent in 2000, and 9.3 percent in 2010.

Weather

Figure 25 charts monthly natural gas consumption in California's four major demand sectors, illustrating the seasonal variation in residential, commercial, and electric generation (power) sector demand.

Cold weather is the principal driver of both residential and commercial sector natural gas demand, as shown in **Figure 25**. In the winter, natural gas consumption spikes as customers in these two sectors ramp up demand for space heating to keep homes and businesses comfortable. As also noted above, total electric generation and hot weather are the dominant factors in seasonal electric generation sector natural gas consumption. High temperatures drive up residential and commercial load on electric power grids, requiring increased

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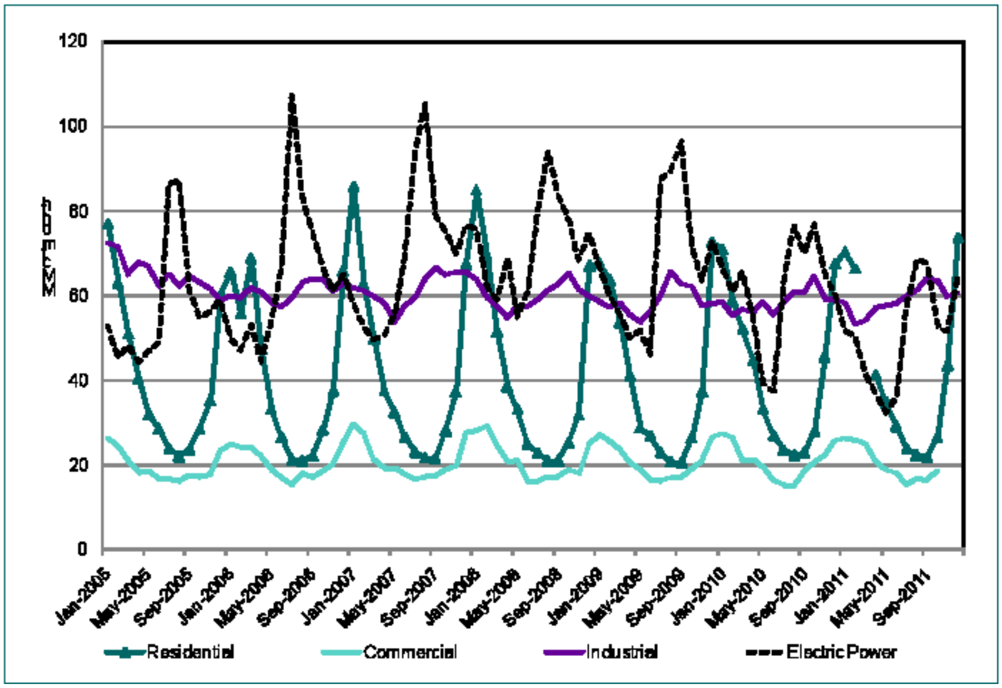
124 Chris Kavalec, Nicholas Fugate, Tom Gorin, Bryan Alcorn, Mark Ciminelli, Asish Gautam, Glen Sharp, and Kate Sullivan, California Energy Commission, *Revised California Energy Demand Forecast 2012- 2022*, 2012, CEC-200-2012-001-SD-V1, Table 3-2, p. 63.

generation from available natural gas power plants to ensure that generation capacity always matches load.

Figure 25: California Seasonal Natural Gas Demand (MMcf/Month)



Source: U.S. EIA, *Natural Gas Monthly*, February 2012.

Population

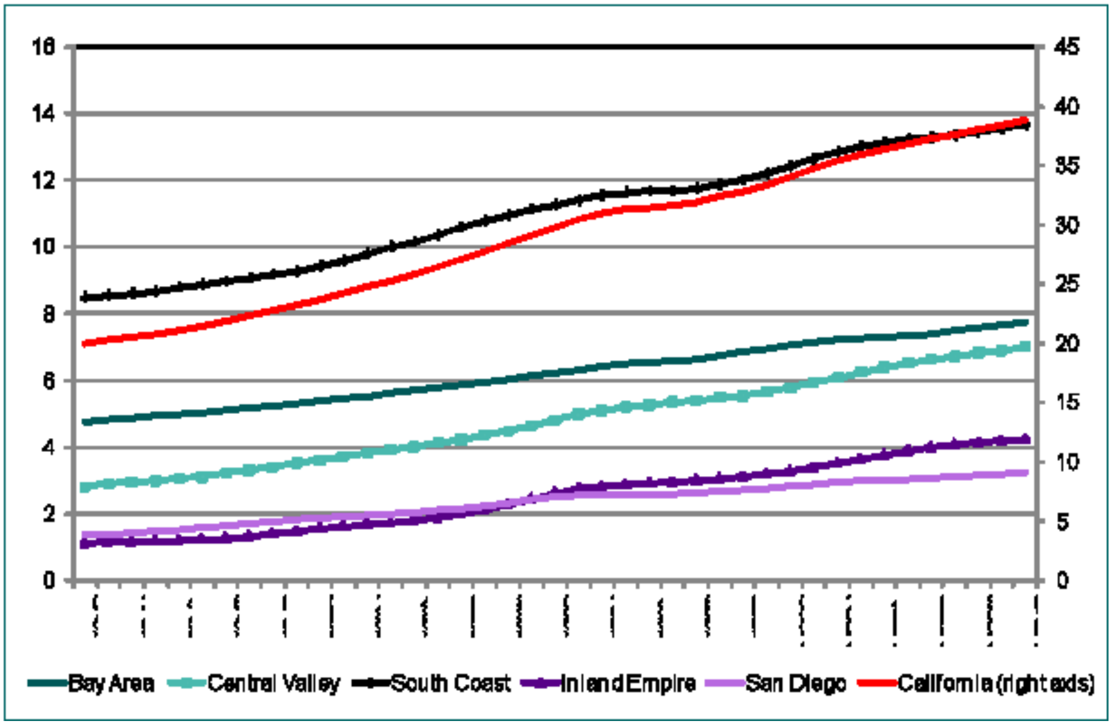
Population is one of the major factors influencing residential and commercial sector natural gas demand. The United States' population has increased significantly over the past decade, as shown in **Figure 26**. The success of energy efficiency, conservation, and renewable resources policies, along with other alternatives to natural gas, is largely responsible for flattening natural gas demand in spite of the countervailing influences of expanding growth in United States population and migration of Americans to hotter climates.

Figure 26: United States Population by Census Regions, 1910 – 2010 (Millions)

Source: U.S. Bureau of the Census.

Similar trends of rising population growth in California and migration of residents to hotter regions can be seen in **Figure 27**. While California's population nearly doubled from 20 million to almost 39 million from 1970 to 2010, increasing shares of that growth are due to population growth not in the state's milder coastal regions, such as the San Francisco Bay Area, South Coast, and San Diego, but in the Central Valley and Inland Empire. Temperatures are colder in the winter and hotter in the summer in these regions than they are near the Pacific Coast. These trends increase natural gas demand to heat homes and businesses in the winter, and natural gas-fired electricity generation to support air-conditioning load in the summer.

Figure 27: California Population by Region, 1970 – 2010 (Millions)



Source: California Energy Commission.

Personal Income

National earnings and other income are also factors that influence demand for natural gas. Given that United States and California personal income over the decade increased by 42 percent and 39 percent, respectively, as shown in **Figure 28**. With this growth, it is reasonable to expect higher spending on natural gas. However, natural gas demand for these sectors did not increase. The United States and California income growth rates since the 1980s have become far more differentiated by wealth cohort. The top 10 percent of Americans, who were paid only a third of annual total national income between 1943 and 1980, earned half of that income in 2007. The top 1 percent of Americans earned almost a quarter of all national income the same year. Real annual income growth for the bottom 99 percent of Americans for most of the past decade amounts to only 1.3 percent.[125] In

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125 Emmanuel Saez, Thomas Piketty, *Striking it Richer: The Evolution of Top Incomes in the United States (Update With 2007 Estimates)*, 2009, p. 5, Figure 1, p. 6, Figure 2, and p. 7, Table 1. This paper defines income before taxes are deducted. Social Security and other transfer payments are added, along with the cash value of public and private health care benefits. It also does not account for multiple tax filers sharing the same households. Accounting for these factors, median household income growth over the past decade is flat.

California, 71 percent of the state's income growth between 1987 and 2009 went to the top 10 percent of residents; meanwhile, the bottom 80 percent received only 14 percent of that income growth.[126] Because income is one of the major factors that influence natural gas demand, the flat income growth most Americans experienced tends to support flat natural gas demand growth.

Figure 28: United States and California Personal Income (Millions Nominal Dollars)

Source: U.S. Bureau of Economic Analysis.

Industrial Sector Natural Gas Demand

Industrial natural gas consumption is influenced by a different set of factors than those affecting the residential or commercial sectors. Manufacturing and assembly processes make this sector much more energy-intensive than the residential or commercial sectors, which is why natural gas price is the second largest influence on this sector's demand. At the same time, rising industrial sector natural gas prices did not result in California industrial sector natural gas demand falling, as shown in **Figure 29**, because again, while prices do not always reduce demand, they are a countervailing influence on demand.

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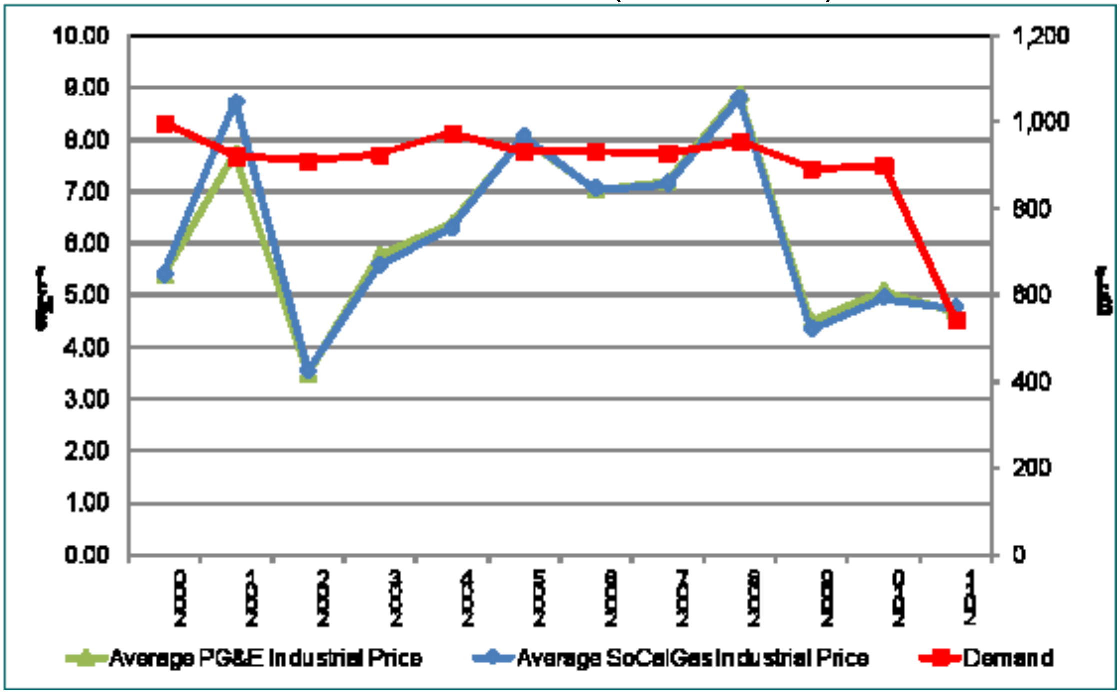
126 California Budget Project, *A Generation of Widening Inequality*, 2011, pp. 13 – 14, at http://www.cbp.org/pdfs/2011/111101_A_Generation_of_Widening_Inequality.pdf.

Figure 29: California Industrial Demand vs. Average Industrial Natural Gas Price (Nominal Dollars)[127]

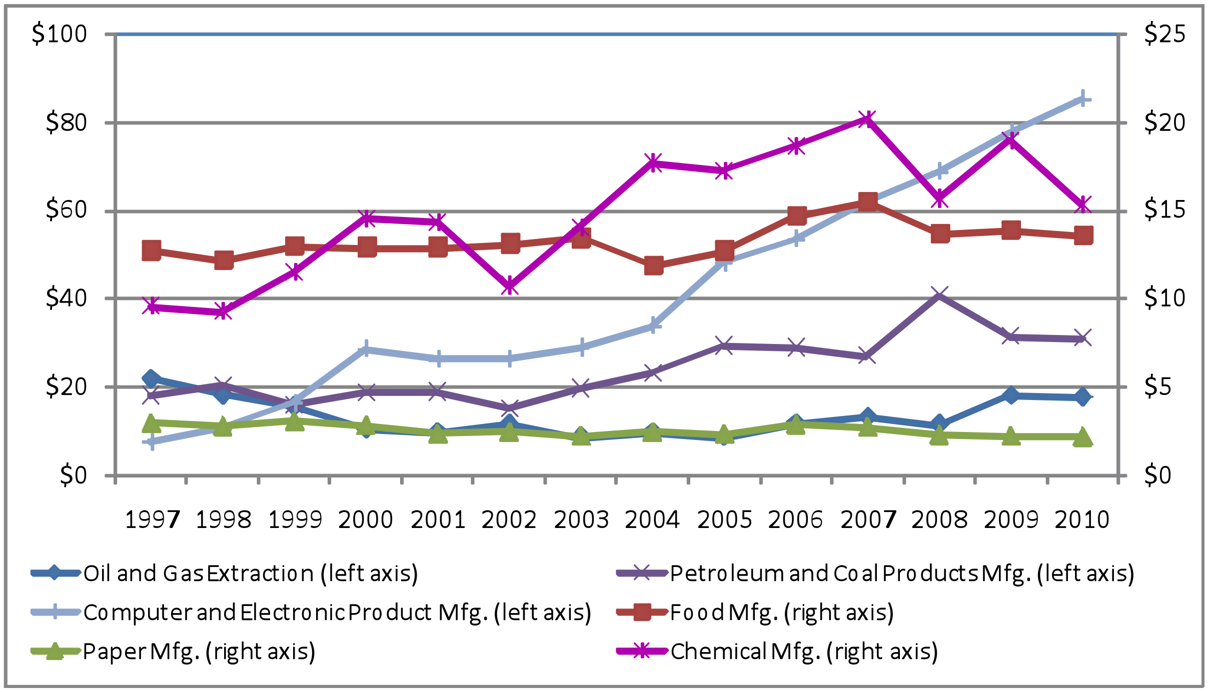


Source: California Energy Commission.

California industrial sector GSP more than doubled, and within that sector, natural gas price trends did not prevent three of the six largest natural gas-consuming industrial subsectors from healthy growth in production, as shown in **Figure 30**. Most of the growth in the industrial sector, shown in **Figure 30**, is due to computer and electronic product manufacturing, which increased from $7.4 billion in 1997 to $85 billion in 2010.

127 The PG&E and SoCal Gas average industrial natural gas prices are estimated backbone- and transmission-level industrial pipeline and Citygate prices.

Figure 30: California Industrial GSP, 2000 – 2010 (Billions of Chained 2005 $)



Source: Moody's Analytics.

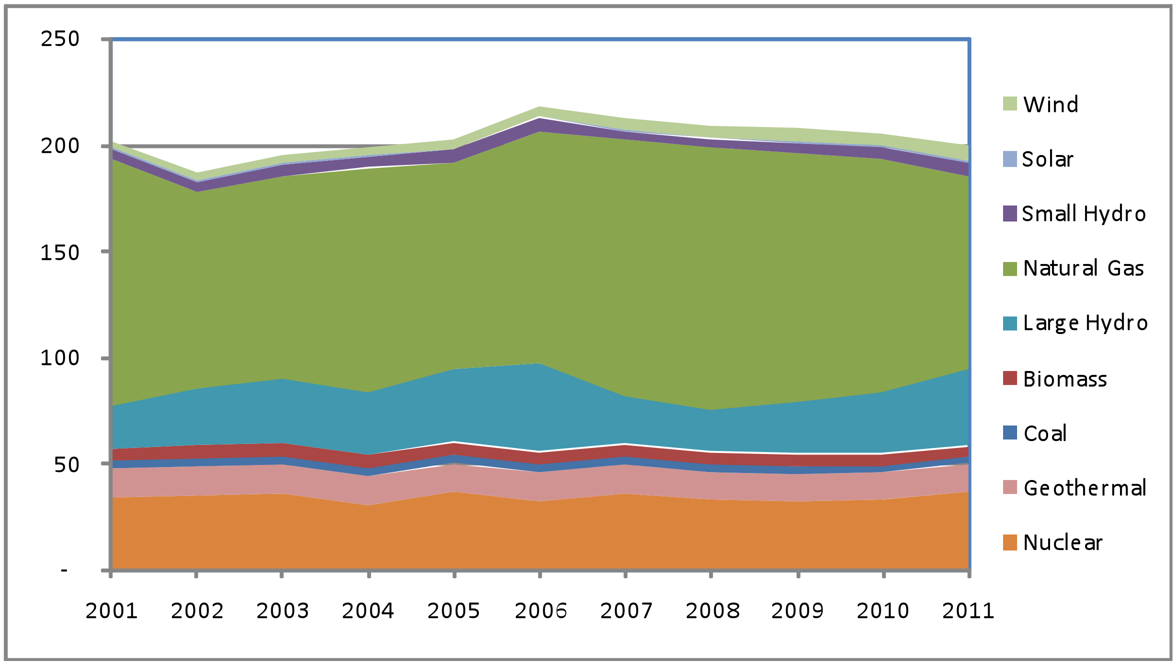
Electric Generation Sector Natural Gas Demand

While the United States has increased its demand for natural gas for electric generation by a third over the past decade, California's electric generation demand has remained relatively flat. In California, the electric generation sector has long been subject to policy measures created to encourage the production and reliable delivery of electricity services with fewer costs to the environment and ratepayers. California relies on a diverse portfolio of generating resources that includes natural gas-fired power plants, cogeneration facilities, hydroelectric dams, nuclear power plants, out-of-state imports, and renewable resources ranging from wind turbines and solar generators to biomass and geothermal plants, as shown in **Figure 31**.

Over the last decade, natural gas-fired generation has been a dominant source of electricity in California, accounting for as much as 59 percent of supplies in 2008. Natural gas consumption for electric generation varies annually, depending on weather and hydroelectric conditions in the state and in the Pacific Northwest. Natural gas serves as swing capacity in the electricity system, making up for shortfalls in hydro production in years when water conditions are below average.

During hotter-than-normal summer weather, natural gas generation can be ramped up to meet peak summer electricity demand. As the demand for air conditioning in the interior portions of the state has increased, so has the need for peaking generation. In recent years, this peaking generation has largely been supplied by natural gas power plants. Natural gas generation also serves as a back-up generation source in the event of nuclear and other generation and transmission outages.

Figure 31: California Electricity Generation by Fuel Type (TWh)



Source: California Energy Commission.

Going forward, California has aggressive goals for increasing renewable electricity generation, with targets of 33 percent of the state's electricity retail sales to be met using renewable resources, 8,000 megawatts (MW) of utility-scale renewables, and 12,000 MW of renewable distributed generation (DG) by 2020.[128] In addition to its contribution to the state's economy, renewable energy also improves California's energy independence by using local energy sources and fuels rather than imported natural gas. Increasing the amount of renewable resources in California's electricity portfolio also benefits the environment by reducing fossil-fuel generation that has negative impacts on air and water quality. Renewable resources are also essential to achieving the state's GHG emissions reduction goals and reducing climate change impacts. California's aggressive renewable energy policies will affect the role of natural gas in the electricity system.

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128 A distributed generation system involves small amounts of generation located on the utility distribution system for the purpose of meeting local (substation level) peak loads and / or displacing the need to build additional (or upgrade) local distribution lines.

While California's system of power resources is complex, generation must, as in all other bulk power grids, instantaneously and continuously match demand. The process of balancing electricity generation to load, while maintaining the voltage and frequency within operational tolerances, is achieved through resource commitment and dispatch. Fitting any particular generating unit into that process, whether conventional or renewable generation, is an effort called "integration." To simultaneously balance electricity supply and demand, a portfolio of power plants are operated or "dispatched" to respond to changing conditions as load varies and as power plant, transmission, or distribution line availability changes, subject to numerous technical and regulatory constraints. Grid operators must plan for hourly, daily, and seasonal fluctuations in electricity demand and the available supply of electricity. Each electricity source has its unique operating characteristics, constraints, costs, and environmental impacts.

As more highly variable, or intermittent, renewable electricity generating resources, like wind and solar, are added to California's electricity resource mix, it becomes more challenging to integrate intermittent resources while maintaining grid reliability, safety, and security. Wind and solar output can rise or drop from moment to moment, across hours, and over days or months. Solar resources begin production after sunrise and more or less shut down at sunset. Intermittency means that operators must forecast what renewable generation will be provided, what services from other sources will be needed, the options to provide these services and their costs, and how to make good choices among the available options.

California relies on the flexibility of its existing generation fleet, particularly large hydropower and natural gas units, to integrate the renewables now on-line. Integration across a mix of generation resources is not a new problem, but the scale and diversity of resources are increasing. Increasing levels of intermittent renewable resources will require a suite of complementary services to help manage the entire grid and match instantaneous load to generating resources. Maintaining a reliable electricity system while adding increasing levels of variable resources will require increasingly sophisticated controls, new market designs, complementary generation, energy storage, and demand response that can be turned up or down as needed. How much future natural gas-fired capacity will be built and the extent to which natural gas capacity will be used in the future are, in part, a function of the penetration of these renewable generation policies and, therefore, also subject to uncertainties affecting the key drivers of renewable generation program success.

Transportation Natural Gas Demand

The use of natural gas as a transportation fuel has grown in recent years in California. After ethanol, natural gas now enjoys the highest demand of any alternative transportation fuel in California, with electricity ranked third. Natural gas demand for urban public transit accounted for 88 percent of all transportation sector natural gas demand in 2009.[129] The growing trend in transportation sector natural gas demand is partly due to an almost eight-fold increase in the number of natural gas-fueled buses from 2000 to 2009, constituting about 10 percent of all buses in the state. Bus travel accounted for about 70 percent of all urban transit passenger trips between 2000 and 2009. Buses and other medium- and heavy-duty vehicles account for most of the historical growth in natural gas transportation demand because they serve regular routes and can be scheduled for timely refueling at compressed natural gas (CNG)/LNG stations available in the state. Despite this growth, alternative transportation fuels — biodiesel, E-85, natural gas, and electricity — reached only 1.6 percent of gasoline-equivalent energy demand in California by 2009.[130]

Natural gas will play a growing role in the state's transportation sector, in response to GHG emissions reduction targets, volatile oil prices, and air quality standards. Future growth in natural gas transportation demand will be driven by measures implementing the state's Low Carbon Fuels Standard (LCFS) and the federal Renewable Fuels Standard (RFS2), which both mandate increasing transportation fuels market penetration of renewable hydrocarbons, natural gas, electricity, and hydrogen. In addition, the Energy Commission's Alternative and Renewable Fuels and Vehicle Program, Assembly Bill 118, (Núñez, Chapter 750, Statutes of 2007) (AB 118), is making investments in natural gas vehicles and fueling infrastructure. Significant opportunities remain for expanding medium- and heavy-duty natural gas vehicles in a variety of applications, which are being funded. The Energy Commission is also supporting the deployment and expanded offerings of light-duty natural gas vehicles through vehicle incentives.

In addition, a modest network of fueling infrastructure already exists for natural gas vehicles. Many of these stations, however, require upgrades, and increases in natural gas vehicles will happen only when concerns about mileage range and fleet fueling operations are resolved. The Energy Commission is supporting new natural gas fueling infrastructure and upgrades to existing infrastructure. In the recently adopted 2012-2013 Investment Plan, the Energy Commission has allocated a total of $1.5 million for natural gas fueling infrastructure.[131]

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129 Gordon Schremp, Malachi Weng-Gutierrez, Ryan Eggers, Aniss Bahreinian, Jesse Gage, Ysbrand van der Werf, Gerald Zipay, Bob McBride, Laura Lawson, Gary Yowell, *Transportation Energy Forecasts and Analyses for the* 2011 Integrated Energy Policy Report, California Energy Commission, 2009, CEC-600-2011-007-SD, pp. 15 – 16, 37, Figure 2-3, pp. 62 and 82.

130 E-85 is a blend of 85 percent ethanol and 15 percent gasoline.

131 *2012-2013 Investment Plan Update for the Alternative And Renewable Fuels And Vehicle Technology Program*, California Energy Commission, May 2012, CEC-600-2012-001-CMF, p. 4.

CHAPTER 5:
Natural Gas Infrastructure Trends

Most of California's natural gas supply comes from the Southwest, the Rocky Mountains, and Canada, while the state produces less than 15 percent of its own needs. Several interstate pipelines deliver the natural gas to the California border, and from there, intrastate pipelines take the natural gas to customers for immediate consumption or to storage facilities for later use. Recent additions of pipeline capacity across the country have allowed access to new shale gas supplies and have created more competition between supply and demand regions, putting downward pressure on prices. The cost of transporting natural gas is expected to increase in response to safety concerns, as discussed in Chapter 3, as well as to potential new environmental regulations. Also, as electric generation demand for natural gas increases, there is a need to examine how to better coordinate the electric and natural gas markets. These and other infrastructure issues are addressed in this chapter.

A complex infrastructure system is necessary to extract and transport natural gas from producers to consumers. **Figure 32** illustrates how the demand sectors are connected to sources of supply through the natural gas infrastructure. As discussed in Chapter 2, widely dispersed production wells tap into the various underground natural gas formations, or "plays." Gathering pipelines move natural gas from the wellhead to local processing plants, which remove impurities and adjust its heat content. Once processed to acceptable standards, the natural gas is considered "pipeline ready. " High-capacity interstate and intrastate pipelines move the natural gas long distances between production regions and major demand areas. Where significant transportation pipelines intersect, market trading hubs with posted prices develop, easing efficient natural gas trading, as discussed in more detail in Chapter 3. Natural gas liquefaction plants, cargo tankers with cryogenic chambers holding LNG, and regasification terminals function essentially as international "floating pipelines," linking natural gas supplies around the world to demand centers.

Natural gas transportation pipelines connect at various locations to natural gas utilities' local distribution pipelines, collectively referred to as the Citygate, which can also function as trading hubs. These locations are where the local natural gas distribution function begins. End users of natural gas are then physically connected to the distribution system. The natural gas flows through the pipelines by keeping it at high pressure. Pressures are maintained by compressor stations and pressure regulators placed throughout the system, which also manage the fluctuations in pipeline pressure caused by short-term imbalances between supplies going into the pipelines and customer withdrawals from the pipelines. Longer-term, seasonal imbalances between natural gas supply and demand are managed by injecting pipeline natural gas into underground storage fields and often depleted oil or natural gas production fields. Natural gas is injected into storage when demand levels are low and spare production is available, and then withdrawn when demand increases.

The following sections address existing and recent additions to pipeline infrastructure, natural gas storage, and LNG facilities. It also discusses several issues that will affect natural gas infrastructure, including natural gas curtailments, the need to harmonize natural gas and electricity markets, and new environmental standards.

Figure 32: United States Natural Gas Infrastructure

Source: *The Future of Natural Gas*, MIT, Modified by MIT from Chesapeake Energy Corporation.

Natural Gas Pipeline Infrastructure

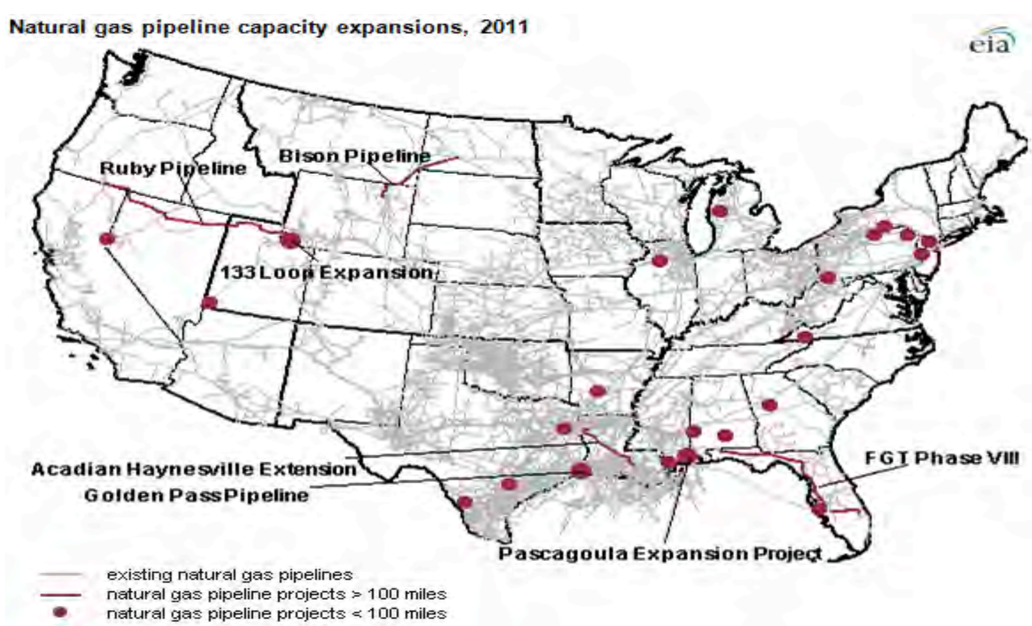
Expansion of Pipelines Nationally

The increase in domestic natural gas production from shale formations has had a profound impact on the amount and location of pipeline capacity additions in the United States. In the past, the focus was to build pipeline infrastructure to move natural gas from the Gulf of Mexico supply region to demand regions to the north, east, and west. With the onset of significant production increases from shale plays, the focus now is to build infrastructure that will transport natural gas from the central supply region of the United States to the western and eastern demand regions. The U.S. EIA reports that companies added about

2,400 miles of new pipe to the Lower 48 states as part of 25 projects in 2011.[132] The 2,400 miles of new pipe roughly equates to 13.7 Bcf/d of added capacity in 2011, which is very close to the amount added in 2010 and well above the 10 Bcf/d levels typically seen for each year from 2001 to 2006. Capacity additions for 2008 and 2009 were exceptional, with 2008 bringing pipeline capacity additions at just over 40 Bcf/d. **Figure 33** shows the locations of major pipeline capacity additions for 2011.

These pipeline additions result in a natural gas infrastructure system that is more integrated than ever before. Most of the capacity additions provide improved connections across the existing natural gas system rather than serving incremental natural gas use. Demand hubs are now more readily linked to supply regions and previous bottlenecks and congestion points relieved. More pipelines mean demand hubs now have more options in the event of a pipeline failure, thus raising the reliability of the natural gas system. Supply hubs are seeing slight increases in natural gas prices as more pipelines can now draw from them. This effect is tempered by the fact that demand hubs now have more pipeline supply options and can choose the cheap- priced natural gas. The result is increased natural gas-on-gas price competitions, leading to a smoothing of basis differentials across all major trading hubs. Improved system reliability, increased price competition, and storage capacity additions all add downward pressure to natural gas prices while minimizing price spike severity. Chapter 3 provides additional information on natural gas price trends.

Figure 33: Natural Gas Pipeline Additions in 2011



Source: U.S. EIA.

132 See http://www.eia.gov/todayinenergy/detail.cfm?id=5050.

The Opal, Wyoming, market hub provides a recent example of pipeline completion at a supply hub. Between 2009 and 2011, construction of the Ruby Pipeline and the REX Pipeline and the capacity expansion of the Kern River Pipeline all occurred here. These and other pipelines are now competing for supplies at Opal, thus providing upward pressure on natural gas prices at this trading hub. However, pricing dynamics are constantly changing at Opal due to shifts in demand from market regions that are now linked to it by pipelines. For example, the REX Pipeline transports natural gas supplies from the Rocky Mountain Region to demand regions in the east. The REX Pipeline has faced increased supply competition from shale plays, such as those located in the Marcellus Basin in the Eastern United States. This competition in the demand regions to the east can have the effect of freeing up supplies and making natural gas cheaper in demand hubs located in the Rocky Mountain region.

Pricing dynamics can also change as a result of market shifts that occur in the supply region itself. Recent trends indicate that natural gas produced in plays with high levels of associated liquids tend to be cheaper than natural gas produced in plays with little or no associated liquids (dry plays). For example, there is natural gas competition occurring at Malin, Oregon, with supplies transported by the TransCanada Gas Transmission Northwest (GTN) Pipeline and by the Ruby Pipeline. Natural gas transported along the GTN Pipeline may have a competitive advantage because it comes from plays in the Western Canadian Sedimentary Basin that have more associated liquids. The Ruby Pipeline transports natural gas from plays that have lower levels of associated liquids. Demand points within California can benefit from this competition by allowing the cheaper-priced natural gas option into its markets.

Interstate Pipelines Serving California

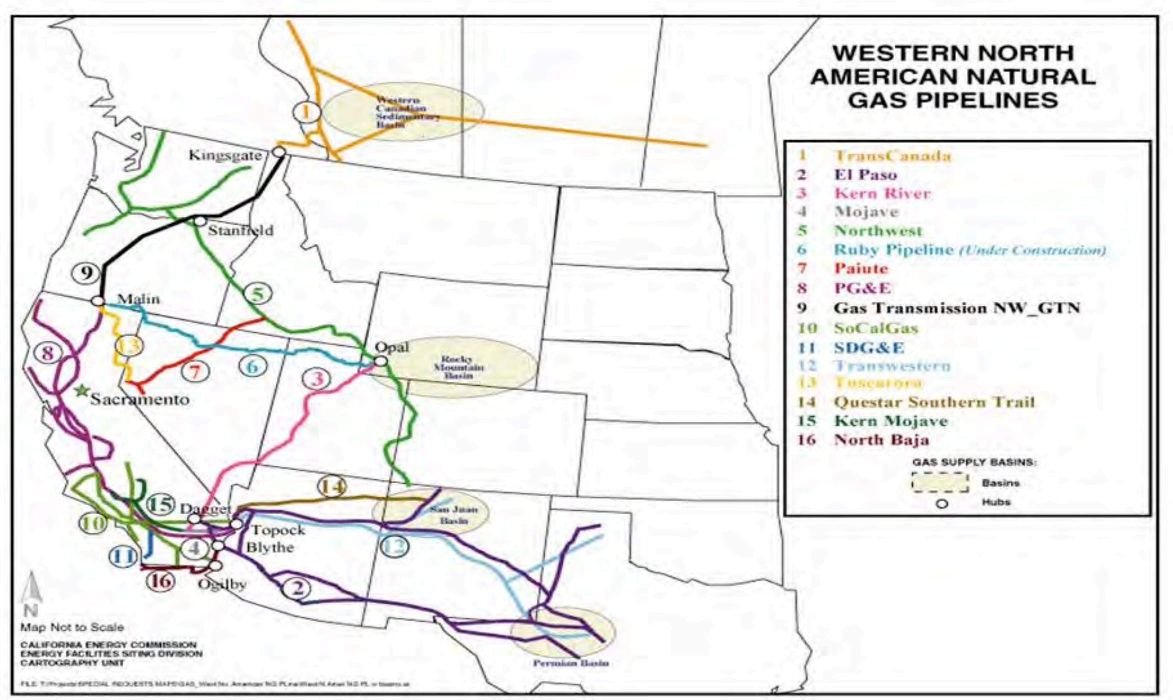
There are six major interstate pipelines that supply natural gas to California, as shown in **Figure 34**. These pipelines link California to supply regions located in the Rocky Mountains, Western Canada, and the Southwest United States. Interstate pipelines deliver a combined capacity of 11.3 Bcf/d of natural gas to California's border, which has an aggregate intrastate receipt capacity of 8.2 Bcf/d.[133] Intrastate pipeline receipt capacity did not keep pace with the capacity increases on interstate pipelines in the last few years, meaning that while there is 11.3 Bcf/d in delivery capacity, only 8.2 Bcf/d of natural gas supply can actually be accepted into the state.[134] PG&E and SoCal Gas companies are responsible for supplying natural gas

133 Lippman Consulting, online database at http://www.lippmanconsulting.com/.

134 An in-depth profile of each interstate pipeline that serves California can be found in William W. Wood, *Natural Gas Infrastructure Staff Report*, California Energy Commission, 2009, CEC 200-2009-004-SR.

to Northern, Central, and Southern California through the use of intrastate and local transmission pipelines.

Figure 34: Western Major Pipelines



Source: California Energy Commission.

An important consideration in understanding natural gas supplies is that California resides at the end of these major interstate pipeline systems. There are many demand points along the interstate pipeline systems that take supply from the pipelines before natural gas ever reaches California. The fact that California is at the end of major interstate pipeline systems could pose potential supply problems should major disruptions occur. However, California now has more pipelines serving it than in years past, providing additional supply options in the event of an interstate pipeline disruption. These new pipelines have intensified natural gas-on-gas price competition at the borders of California.[135]

The Ruby Pipeline, LLC, began operation on July 28, 2011. The project consists of a 42-inch natural gas pipeline that extends for 680 miles.[136] The interstate pipeline crosses four states

135 When two natural gas pipelines meet at a single hub, usually the cheaper-priced natural gas is purchased and allowed to proceed to the demand point. This is referred to as *gas-on-gas price competition.*

136 See www.rubypipeline.com.

beginning at the Opal Hub in Wyoming and terminating near Malin, Oregon. The Ruby Pipeline has an initial design capacity of up to 1.5 Bcf/d and accesses natural gas supplies in the Rocky Mountain region. Supplies of natural gas from the Ruby Pipeline helps offset decreasing deliveries from the Western Canadian Sedimentary Basin and relieves demand congestion on pipelines in the Northwest.

As mentioned, increased competition from the addition of the Ruby Pipeline has already elevated prices for natural gas at the Opal Hub. However, the Ruby Pipeline is delivering natural gas at a price that is highly competitive at the Malin Hub (Oregon). This has the effect of backing-off natural gas north on the TransCanada GTN Pipeline through displacement. The Ruby Pipeline is in essence bringing an additional option of natural gas to the Northern California border, which can dampen prices.

On April 13, 2012, TransCanada announced that flow along GTN Pipeline will become bi-directional and an agreement with El Paso's Ruby Pipeline had been established. TransCanada now has permission to offer firm service north on GTN Pipeline to Ruby Pipeline. The agreement goes into effect on November 1, 2012. The bidirectional flow will allow TransCanada to better serve the Pacific Northwest market.

Construction for Kern River's Apex Expansion Project commenced during the fall of 2010 and was placed into service on October 1, 2011. The project increased the amount of natural gas on the Kern River's interstate pipeline by 266 MMcf/d, bringing the total system capacity up to 2.14 Bcf/d. The primary purpose of the project was to service the Apex power station in Las Vegas, but it has also freed up delivery capacity to California.

The current capacity for the North Baja Pipeline connecting to Mexico is 500 MMcf/d but may be expanded as high as 1.0 Bcf/d in the near future. Recent deliveries into Southern California along the North Baja Pipeline, as a result of LNG shipments to Costa Azul, are addressed in further detail in the LNG section of this chapter.

Pipeline capacity additions and increasing competition between pipelines can cause some pipeline systems to become underused. On January 6, 2012, El Paso Natural Gas (EPNG) filed with FERC seeking authorization to abandon two compressor facilities and partially abandon four compression stations located in the San Juan Triangle System and North Mainline System, respectively. Abandoning compressor facilities has the effect of reducing the capacity on the pipeline system. EPNG has deemed these facilities are no longer needed to provide long-term natural gas transportation service. Between the two systems combined, EPNG estimates there will be a capacity reduction of 651 MMcf/d on a summer basis and a reduction of 627 MMcf/d on a winter basis. EPNG is requesting that FERC issue its decision by December 31, 2012, so that the abandonment process can begin in the first quarter of 2013.

Many interveners in the FERC proceeding have expressed concerns with EPNG's request for capacity abandonment.[137] SCE argues that natural gas from the San Juan Basin coming on the El Paso north mainline currently sets the marginal cost of natural gas in Southern California. The extra capacity currently available in El Paso north is used by shippers of natural gas on a short-time basis, which in turn increases natural gas-on-gas competition. BP/Shell/Conoco-Phillips (the Shippers) indicate that the expenses for the facilities El Paso is trying to abandon are already included in the shipping rates and that demand for the extra capacity already exists. The Shippers claim that EPNG is trying to create a justification to increase its tariffs. SoCal Gas, PG&E, and SDG&E indicate that EPNG has actually rejected some offers for long-term firm capacity contracts in November 2011, indicating that there is interest in firm capacity. In addition, the compression facilities are being used to transport natural gas across mainlines (El Paso North mainline through Havasu lateral to El Paso South mainline). Abandoning these facilities will affect natural gas deliveries into Southern California. The CPUC has also submitted a protest indicating that the facilities are being used and serve the purpose of delivering low-cost natural gas into California.

Liquefied Natural Gas Infrastructure

World LNG Trends

With an estimated 16,200 Tcf in proven and potential reserves, there are extensive supplies of natural gas around the globe.[138] However, most of this supply is concentrated in certain countries, with Russia, the Middle East, and North America holding 70 percent of the world supply base. Each of these regions has its unique geopolitical climate that affects access to its respective natural gas resources. Around the world, there is a significant amount of activity in the early phase of producing natural gas from shale formations, as indicated in Chapter 2. However, outside North America, this type of unconventional natural gas supply has not yet reached the level of large-scale production. There is no push to develop unconventional natural gas supplies when conventional resources are abundant. The cost of transporting natural gas to market, whether by pipeline or in the form of LNG, is the largest cost component for natural gas around the world. For this reason, markets that are in relatively close proximity to production regions will incur smaller transportation costs. Increased LNG shipping capacity around the world has helped connect countries with large amounts of natural gas to countries with growing economies, but with little or no domestic supplies of natural gas.

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137 Filed under FERC Docket No. CP12-45-000.

138 Massachusetts Institute of Technology, *The Future of Natural Gas: An Interdisciplinary MIT Study*, 2010, p. 7.

Most of the new LNG supplies that were originally intended for the North American market have found their way to other markets, such as Europe and Asia. World regasification capacity combined is 30.3 Tcf/yr, with 6.3 Tcf/yr attributed to the United States.[139] However, much of this regasification capacity in the United States is largely underused. In the United States, the landed price of LNG is linked to the price of domestic natural gas, which has been relatively low in recent years due to increased supplies from unconventional sources, such as shale gas. Other world markets lack the energy alternatives that are currently available in the United States. In the European and Asian markets, LNG is indexed against the price of crude oil. For most of 2011, prices offered for LNG in North America had consistently been $6 to $9 less than prices offered in other markets around the world. Consequently, LNG imports to North America declined to record low levels in 2011 as exporters shipped supplies of LNG to other higher-priced markets.

Japan is importing more LNG since earthquakes and tsunamis affected 11 of its nuclear plants. Japan's increased demand for LNG has added upward pressure on LNG prices in both the European and Asian markets. While LNG prices rose steadily in other markets, they remained relatively low and stable in the United States. Increased supply from shale plays shields the United States from LNG price fluctuations felt around the world.

United States LNG Trends

Currently, there are nine LNG import facilities in the United States located along the East Coast and Gulf Coast. Three of these facilities have received permission to re-export LNG. However, these facilities are only approved to re-export LNG to countries covered under the Free Trade Agreement (FTA) and are seeking approval from the U.S. DOE to export to countries not covered under the FTA. To approve an export permit for an LNG facility, the U.S. DOE must determine it to be in the "national interest." Sabine Pass LNG is the only LNG facility located in the Lower 48 states that has gained approval from the U.S. DOE to export to countries not covered under the FTA. On April 16, 2012, FERC approved the proposal by Cheniere Energy units (Sabine Pass Liquefaction LLC and Sabine Pas LNG LP) to site, construct, and operate facilities to liquefy domestic natural gas for export to markets worldwide. When built, Sabine Pass LNG will be capable of exporting 2.2 Bcf/d. FERC ordered that the proposed facility be constructed and available for service within five years of the project approval date. Cheniere Energy Partners LP is arranging financing for the export project and thus far secured eight financial institutions to help finance the project.

Other applicants for LNG export permits are waiting while the U.S. DOE considers findings of potential impacts on domestic markets from one study by the U.S. EIA and in another

139 *Market Review*, (Paris, France 2010), p.1.

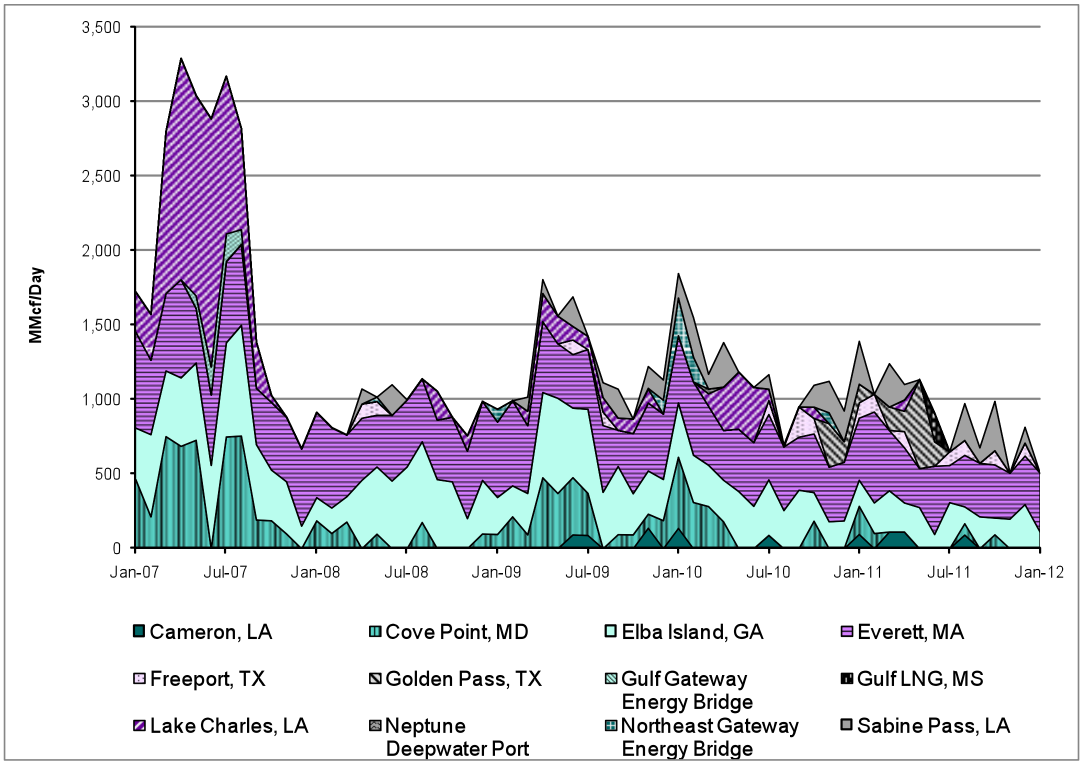
study expected to be released in the spring of 2012.[140] It is expected that the U.S. DOE will then hold a public comment period after the release of the second study. A discussion of the impacts to domestic natural gas prices from LNG exports can be found in Chapter 3.

There is an LNG liquefaction export facility located in Kenai, Alaska, which Conoco Philips gained ownership of by purchasing Marathon Oil Corporation's 30 percent share on September 26, 2011. Conoco Phillips announced that it has secured natural gas supplies for the facility and intends to supply LNG to the Asian market through the spot market. The facility had been selling LNG to Japan for more than 40 years. The plant's export license is set to expire in 2013.

As mentioned, shale gas supply is suppressing domestic natural gas prices in the United States, causing declines in LNG imports. During 2010, the gap between the Henry Hub spot price and the United Kingdom National Balancing Point spot price widened, leading to a 35.2 percent decrease in 2011 LNG imports when compared to 2010. Annual imports of LNG peaked in 2007 and have generally declined since. Imports in 2009 exceeded the amount imported in 2008 but were still low compared to prior years' imports, as shown in **Figure 35**. Most of the imports for 2009 came at a time when prices for LNG in the United States were competitive with prices in other world markets.

140 The U.S. DOE has not yet disclosed the name of the consultant conducting this study.

Figure 35: LNG Imports to the United States



Source: California Energy Commission.

California LNG Trends

Currently, there are no LNG import or export facilities located in California. Six years ago, there were as many as four LNG import projects being proposed for California.[141] Of the four projects that formally applied for construction permits, two had their applications rejected for failing to meet environmental standards, while the other two projects halted application activity due to unfavorable market conditions. A few years ago, domestic production of natural gas was declining in the United States. Although imports from Canada were making up the difference, production in Canada was also declining, leading to expectations of declining deliveries to the United States in the coming years. At the time, the price of natural gas was rising, which provided companies the incentive to build LNG import facilities along the California coast. However, the market changed with increasing supplies of natural gas from unconventional sources.

141 The four projects that were proposed include Cabrillo Port LNG Facility, Clearwater Port LNG Project, Long Beach LNG Facility, and OceanWay LNG Terminal.

Costa Azul, an LNG import facility owned by Sempra, has been in operation in Baja California, Mexico, since 2008. LNG-sourced natural gas from this facility can find its way into the Southern California market through the North Baja Pipeline. The North Baja Pipeline is bidirectional, with natural gas flowing south into Mexico since June 2010. However, Sempra LNG has contractual obligations to supply natural gas to two power plants located in Northern Mexico. Any surplus natural gas has the possibility of finding its way into Southern California.

From April to June 2010, Southern California received an average delivery of 140 MMcf/d of LNG-sourced natural gas.[142]. Costa Azul was able to receive deliveries of LNG because Sempra was paying a discounted price to exporters in lieu of shipping to other, higher-paying markets. However, Costa Azul has not received any shipments of LNG since January 2011. Costa Azul must compete in the Pacific Basin for its LNG. Currently, other countries in the Asian market are paying a much higher price for LNG, making it difficult for Costa Azul to attract shipments of LNG.

On March 28, 2011, an LNG regasification import facility came on-line in Manzanillo, located on the Pacific Coast of Mexico. This LNG facility has a capacity of 500,000 Mcf/d and will receive shipments of LNG from Peru. The capacity owner is the Federal Electricity Commission of Mexico, or CFE Mexico, which uses the natural gas to produce electricity.

Natural Gas Storage

Natural gas can be stored in underground storage facilities, pipelines, and above-ground storage tanks. Natural gas in underground storage facilities must be maintained at high pressure, which requires a certain amount of cushion natural gas. The storage capacity minus the cushion natural gas is what is called the *maximum working capacity* for the underground storage facility. Natural gas can also be stored in pipelines for what is called *line packing*. This is done by packing more natural gas into the pipeline using increased pressure. Line packing is usually performed during off-peak times to meet the next day's higher peaking demands. This method, however, provides only a short-term substitute for traditional underground storage. The following section addresses only underground natural gas storage facilities, which is the primary natural gas storage for California.

Natural gas storage levels thus far for 2012 are unprecedented on a national scale. Persistent, robust production of natural gas and a relatively mild winter that contributed to lax demand for natural gas have resulted in the highest level of natural gas storage for the winter season ever seen in the United States, as shown in **Figure 36**. With storage inventory levels currently at about 2.5 Tcf (as of March 2012), about 0.8 Tcf over last year's level for

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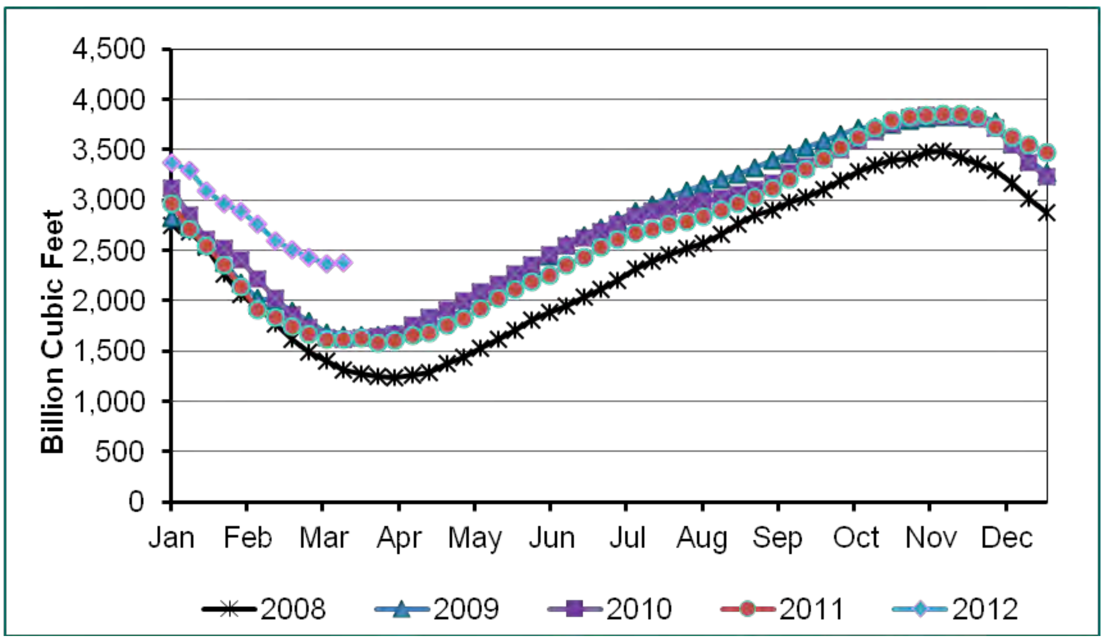
142 Lippman Consulting, Pipeline Reports Database.

this time, the national storage capacity limit may be reached by September 2012.[143] The maximum working natural gas capacity for the Lower 48 States is 4.4 Tcf.[144] These exceptional storage levels will only compound the existing downward pressures on natural gas prices.

There are 10 operating natural gas storage facilities in California, which use depleted oil or natural gas production fields. All but three of them are owned by either PG&E or SoCal Gas. The other three facilities, while independently owned and operated, still fall under CPUC regulation. Utility and independent facilities combined have a storage capacity of 313.7 Bcf. In October 2011, FERC approved Tricor Ten Section Hub LLC's proposal to convert a depleted oil and natural gas reservoir in Southern California to a high-deliverability, multicycle storage facility. The natural gas storage facility is expected to be available for service starting in early 2013. **Table 6** shows existing and proposed natural gas storage facilities in the state.

Figure 36: United States Natural Gas Storage



Source: California Energy Commission

143 Natural gas storage levels for California as a whole are currently not available. Inventory levels for the SoCal system are available, but inventory data for the PG&E system are deemed proprietary information and are not reported.

144 See http://205.254.135.7/naturalgas/annual/pdf/table_014.pdf.

Table 6: California Natural Gas Storage

Northern California	Maximum Working Capacity (Bcf)	Southern California	Maximum Working Capacity (Bcf)
Existing		Existing	
Subtotal	**180.6**	**Subtotal**	**133.1**
Proposed		Proposed	
Wild Goose	21.0	SoCal Gas	7.0
Sacramento	8.0	Tricor Ten Section	22.4
Central Valley	5.5		
Subtotal	34.5	**Subtotal**	29.4
Northern CA Total	**215.1**	**Southern CA Total**	**162.5**
Statewide Total Existing and Proposed			**377.6**

Source: California Energy Commission, based on data collected directly from storage operators.

Issues Affecting Natural Gas Infrastructure

Natural Gas Curtailments in the Southwest and California

Recently, extremely cold weather in Texas caused the outage of both electric generation and natural gas production in the state, resulting in unexpected natural gas shortages and electricity service interruptions in Southern California. On Thursday, February 3, 2011, all interruptible and some firm noncore customers of SoCal Gas and SDG&E received no shipments of natural gas as a result of freezing weather in New Mexico and Texas. The curtailment lasted roughly 21 hours. This incident serves as an example of the increasing interactions between electricity and natural gas markets and the need for good coordination between the two.

Shortly after midnight on the morning of February 2, 2011, overnight temperatures of around zero degrees for areas in North and West Texas and temperatures down into the teens for areas in Central Texas combined with high winds to force six coal-fired electric generating units in Texas offline. Some of the outages were caused by bursting water pipes and others by freezing instrumentation. Together, 4,800 MW of coal-fired generating capacity was forced off-line.[145] Some natural gas power plants that would normally be called

145 Some published accounts say Electric Reliability Council of Texas lost as much as 7,000 MW of generation.

on to provide replacement generation were initially unavailable due to rapidly rising morning demand. Other natural gas generators could not operate because pipeline pressures, which were reduced by freezing of natural gas wells and gathering lines, were too low.[146][147] In addition, many of the replacement natural gas units had purchased only interruptible natural gas transportation service, which was unavailable due to high demand by higher priority customers. The high heating demand for natural gas was also a by-product of the extremely cold weather.

These electricity outages initially included service to natural gas-processing and pipeline compressor stations that use electricity to run the compressors or auxiliary equipment. The effect of some well and gathering line freeze-ups, combined with the electricity outages to natural gas operating facilities, caused shortages of pipelines deliveries at the same time that customers were demanding near-record levels of natural gas. EPNG, whose southern mainline moves natural gas from Texas into New Mexico and ultimately to California, noticed that scheduled deliveries into its system were not materializing. This caused operating pressures to drop, meaning that less natural gas could flow westward to New Mexico, Arizona, and California. The pressure drop occurred despite efforts by EPNG to maintain operating pressure by increasing line pack, and by withdrawing some natural gas from underground storage. TransWestern pipeline also noticed a drop in system deliveries and issued critical operating notices to its shippers, warning that line pack was dangerously low.

On February 3, 2011, SoCal Gas and SDG&E sent a notice to all interruptible and firm noncore natural gas customers located in Riverside, Imperial, and San Diego counties that deliveries could be curtailed. SDG&E also asked customers to conserve both electricity and natural gas. Following the announcement, SDG&E cut or reduced natural gas deliveries to all 88 of its industrial customers, including natural gas-fired power plants. SoCal Gas cut natural gas supply to 20 customers in Imperial and Riverside counties and reduced natural gas flow to 28 others. These were all noncore customers who are required to accept service cutbacks during shortages but who arguably pay lower natural gas transportation rates in exchange for the curtailment risk. During this time, natural gas spot prices in Southern California increased two to three dollars above the Henry Hub and PG&E Citygate price. Warming weather conditions and increased reliability of natural gas deliveries into EPNG's southern system allowed SDG&E and SoCal Gas to lift the curtailments on February 4, 2011.

In August 2011, the FERC and the North American Electric Reliability Corporation (NERC) issued a joint report (the *FERC/NERC Joint Report*) on the outages and curtailments during

146 The minimum operating pressures for these gather lines vary between 400 psi to 600 psi.

147 Gathering lines are pipelines that connect natural gas wells to production facilities in gas fields.

the Southwest cold weather event of February 2011.[148] In this report, key findings and recommendations are identified for both the electric side and natural gas side of the event.

On the electric side, the *FERC/NERC Joint Report* found that the Electric Reliability Council of Texas (ERCOT) planned for adequate reserve margins based on anticipated generator availability. However, these reserve margins proved insufficient because more than 29,000 MW of generating capacity was lost due to trips, derates, and failures to start. It was also discovered that a substantial amount of generating facilities, totaling 11,566 MW were down for scheduled maintenance during the cold weather event. ERCOT's swift action to enact load shedding most likely prevented more widespread, uncontrollable blackouts in the ERCOT control area.[149] The preventive action of load shedding did affect natural gas gathering facilities, processing plants, and compressor stations, facilities that were not previously identified as "critical and essential" loads.

For the electric side, the *FERC/NERC Joint Report* recommends that planning reserves be set for the winter season based on the amount of generating capacity that can be dependably counted on during extremely low temperature conditions. Short-term operations planning should also be done by taking low temperature conditions into account. The *FERC/NERC Joint Report* also recommended that ERCOT review its rule for approving planned outages during cold weather conditions. There are a number of other recommendations on the electric side, including better coordination among transmission operators, balancing authorities, and generation operators; improved winterization of critical load facilities; and implementation of routine maintenance, inspection, and training.

On the natural gas side, the *FERC/NERC Joint Report* found that the extreme low temperatures caused widespread wellhead, gathering system, and processing plant freeze-offs, as well as hampering repair and restoration efforts. Electrical outages contributed to the weather problems faced by natural gas producers, but it was later learned that the electric blackouts had a less important effect on natural gas supply shortages than did the low temperature conditions. The combination of supply shortages and unusually high demand resulted in low delivery pressures along the EPNG interstate pipeline. However, the *FERC/NERC Joint Report* concluded that the pipeline network exhibited good flexibility in adjusting to meet demand and compensated for supply shortfalls. It concluded that additional natural gas storage facilities in Arizona and New Mexico could have helped prevent outages by providing additional supply during periods of peak demand, thus raising system reliability.

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148 See http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf.

149 Load shedding is cutting off the electric current to customers when demand is greater than supply to avoid blackouts and system disruptions.

The *FERC/NERC Joint Report* recommends that lawmakers determine if shortages due to extreme weather conditions can be economically mitigated through the establishment of minimum, uniform standards of winterization for natural gas production and processing facilities. It also suggests that lawmakers, working with their state regulators and all sectors of the natural gas industry, should also determine if natural gas facilities should be identified as a critical load and not subject to rolling blackouts. The FERC/NERC Joint Report recommends a review and update of curtailment plans and priority for natural gas customers in light of new information gathered from this event. It also recommends upgrades to the natural gas distribution system to allow for improved and responsive curtailments, as well as increased natural gas flow, during periods of high demand.

EPNG has reported that it is using the many lessons learned from this event to improve communication and coordination throughout its natural gas distribution system. Measures are being put in place to ensure that power remains available to run compressor stations in the event of extremely cold weather conditions. EPNG is also analyzing the feasible level of investments in winterization of equipment associated with the entire process of natural gas delivery.

Natural Gas-Electricity Harmonization

Considerable activity is occurring and is expected to continue over the next couple of years on the issue of natural gas and electricity "harmonization." As the natural gas and electric industries have become increasingly interdependent, there is a need to better coordinate pipeline delivery of natural gas and electric system reliability. The effort recognizes that key differences in standard operating procedures between the two industries prevent the seamless operational interaction needed to support both the replacement of the coal-fired fleet with natural gas-fired generation across the United States, and the increasing use of natural gas-fired units to integrate intermittent renewable generation. Electric generation demand for natural gas is discussed in more detail in Chapter 4.

The February 2011 cold weather event that caused rolling outages of electricity in ERCOT and natural gas curtailments to parts of Texas, New Mexico, Arizona, and Southern California discussed in the previous section helped demonstrate the importance of the issue. System operators had not realized that important natural gas facilities were operated with electricity, and that protocols were needed to ensure continued operation of those facilities during rolling electrical outages. System operators also became aware that just because a natural gas-fired unit was physically present, it may not have the necessary firm natural gas delivery capacity or supply contracts that would ensure they could operate in extreme conditions. They also recognized that they needed more advance information about the status of natural gas pipelines, and what the pipelines and local natural gas distribution companies might be doing to prepare for extreme weather events.

Recent studies have also helped focus attention on the harmonization issue, including an American Public Power Association (APPA) study by Aspen[150] and an MIT[151] study, both released in 2010. The studies cited the need to resolve infrastructure constraints and limitations as natural gas displaces coal in the electricity generation mix. Subsequently, in 2011 the National Petroleum Council released a study that identified issues similar to the APPA study.[152]

In particular, it highlighted the differences between the natural gas day and electricity day, and the fact that the electricity day differs by region. Integrating renewables into the electricity system by addressing intermittency, as discussed in Chapter 3, further magnifies the need for harmonization. Specifically, discussions of using natural gas to integrate renewables derive from the ability of natural gas-fired combustion turbines to quickly ramp up or ramp down. They tend to ignore the fact that if the natural gas was not nominated the day prior, then either the natural gas-fired generator is actually burning natural gas in the system as line pack, provided and managed by the natural gas utility, or it is taking another user's natural gas.[153] Moreover, natural gas moves within a pipeline relatively slowly, which is why most natural gas systems require ratable hourly nominations in recognition that natural gas pipeline systems cannot quickly change.

Many of the rules, protocols, and operating procedures for the natural gas industry were developed in the late 1980s and early 1990s. At this filing, FERC mandated natural gas pipelines to restructure and offer open access services to enable the natural gas spot market that had developed. In that era, electric utilities, particularly those outside California, relied on natural gas-fired facilities to meet a smaller proportion of load than they do today. In addition, the natural gas system's primary focus has been on maximizing the reliability of service to residential and small commercial customers. The complex and associated high cost of restoring service to individual homes and business, not to mention the danger of allowing uncontrolled natural gas outages, is well documented.[154] Thus, the rules and protocols need to be revisited so they can better meet the needs ratepayers have today.

150*Implications of Greater Reliance on Natural Gas for Electricity Generation*, produced by Aspen Environmental Group for the APPA, July 2010.

151 Moniz, et al., *Future of Natural Gas, Interim Study*, MIT, 2010, p. 65.

152 "*Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources," National Petroleum Council*, September 2011. See http://www.npc.org/Prudent_Development.html. (Accessed March 2012.)

153 A nomination is a request for a physical quantity of natural gas under a specific purchase, sales, or transportation agreement, or for all contracts at a specific point on the gas pipeline system.

154 See, for example, "*Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5 2011,*"(*FERC/NERC Staff Report*), August 2011, p. 125 and p. 132 and Pacific Gas and

Other examples of natural gas-electricity harmonization issue include:

- Physical inability to locate the natural gas storage needed to help regulate linepack or back-up generation in all geographic regions of the United States.
- Mismatch between natural gas industry nomination and scheduling natural gas day versus electricity scheduling and dispatch, including the fact that natural gas is nominated before electricity dispatch is determined.
- Electricity markets operate on weekends, but natural gas markets do not.
- Requirements for ratable hourly takes or high–cost, "no-notice" natural gas service need to be accounted for.[155]
- Natural gas-fired generation facilities may not hold firm pipeline capacity or firm supply contracts to support the ability to operate under all conditions.
- Natural gas-fired generators that may operate only on-peak or unpredictably are unable to hold firm pipeline capacity or contract for firm natural gas supply because they are uneconomic under current market structures.
- End-use curtailment policies behind local distribution company Citygates have not been updated to reflect the need for firm access to ensure reliable operations by natural gas-fired generation.
- Mismatch between the costs for that natural gas-fired generator to operate reliably and the recovery of those costs in electricity market prices.

Various discussions and activities are now occurring that recognize the need to harmonize natural gas and electricity markets, and their physical operations, including:

- On January 25, 2012, the Pacific Northwest Utilities Conference Committee (PNUCC), Northwest Gas Association, and BPA hosted a summit in Portland, Oregon, to discuss interface issues. FERC Commissioner Phillip Moeller attended.[156]

Electric Company, "*Report Of Pacific Gas And Electric Company On Records And Maximum Allowable Operating Pressure Validation*," in CPUC Rulemaking 11-02-019, February 24, 2011, p. 20.

155 This is significant because gas requirements for power plants are simply not ratable. Even for a baseload gas-fired power plant, the variation in heat rate efficiency causes its gas requirement to vary, exposing the plant to balancing charges. A peaker, whose gas requirement may be zero in some hours, then ramps up to full output and back down, is inconsistent with the way the gas system is designed. Services that allow for no-notice takes are not feasible for every pipeline or LDC to offer and when they are offered, generators cannot necessarily recover the associated cost.

156 PNUCC has posted the presentations that day at http://www.pnucc.org/system-planning/natural-gas-for-electric-power/plugging-natural-gas-2012-energy-summit-january-25-20. Of particular focus

- FERC Commissioner Moeller issued a letter asking the industry to comment on questions relating to harmonization on February 3, 2012. Among other things discussed, Commissioner Moeller asked what FERC's role should be in resolving the differences between the two industries, how to balance regional differences (particularly between regions with organized markets versus bilateral markets), whether FERC would need to address changes in pipeline flows as more generation uses natural gas, and how to harmonize the different natural gas-electric trading days.[157]
- The Midwest Independent System Operator (MISO), in early February 2012, issued a study on natural gas and electric infrastructure interdependency.[158] MISO's president issued a statement at the National Association of Regulatory Utility Commissioners (NARUC) 2012 Winter Meetings listing issues on which FERC and NERC should take action. The release coincided with the first meeting of the newly launched NARUC/FERC Forum on Reliability and the Environment, intended as an opportunity for state and federal energy regulators to discuss reliability implications of the EPA rules many believe will lead to greater reliance on natural gas for electricity generation.
- DOE's Assistant Secretary for Energy Delivery and Energy Reliability, in a March 2, 2012, memorandum, recognized the issue by accepting the recommendation of the Electricity Advisory Committee to help address this issue by facilitating further analysis and discussions between oversight and policymaking agencies.[159]
- The North American Energy Standards Board (NAESB) convened a committee to discuss harmonization issues and recommend to the NAESB board whether there are business standards it should adopt to address them. The 37-member committee is scheduled to make a recommendation by September 2012.[160]

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that day was the January 2009 incident in which a compressor at the Jackson Prairie gas storage facility failed, one of them highlights.

157 Commissioner Moeller set a due date of March 30, 2012. The Commission subsequently opened a formal docket (AD12-12-000) to accept the comments.

158 EnVision Energy Solutions, *Gas and Electric Infrastructure Interdependency Analysis,* February 2012. See https://www.misoenergy.org/AboutUs/MediaCenter/PressReleases/Pages/BearCommentstoNARUCFERCForumonReliabilityandtheEnvironment,Washington,DC,Feb7,2012.aspx. (Accessed March 2012).

159 Memorandum from Patricia Hoffman. See http://energy.gov/sites/prod/files/DOE%20Response%20to%20EAC%20Recommendations%20-%20March%202012.pdf. (Accessed March 2012.)

160 NAESB provided a report to FERC with recommendations in 2005 (Docket No. RM05-28-000) *NAESB Report on the Efforts of the Gas-Electric Interdependency Committee*" Nothing was ultimately adopted from that effort because the industry failed to agree on solutions.

A number of factors help to ameliorate some of these issues for California in comparison to other states including:

- California's abundance of underground natural gas storage located near its load centers and its policy to encourage construction of independent natural gas storage.
- California's policy to encourage construction of interstate pipeline capacity above average day requirements and from diverse supply basins.
- The flexibility built into the transmission and distribution systems of large natural gas LDCs and their posting of information about system conditions.
- The fact that California's size yields a large natural gas market that is sought after by providers, and is liquid and robust.
- California's aggressive policies to increase renewable resources and the fact that it has essentially no coal-fired units located inside the state, and is reducing its reliance on out-of-state coal.

To address the renewable integration issue, however, California still needs to evaluate the potential subhourly requirement for natural gas relative to natural gas system operating conditions. Part of the concern is related to the low-demand periods in which the incremental demand from bringing natural gas units on-line could be large, relative to total system natural gas demand. Under these conditions, if the natural gas-fired units that California would be relying on for those days are located where line pressures are low, generation may not be able to come on-line, which raises concerns. There may be other pressure-related issues that have not yet been identified because California is still evaluating the renewable integration needs of the state.

Environmental Standards for Natural Gas Infrastructure

New Emissions Reporting Requirements for Small Natural Gas Facilities

On November 8, 2010, the U.S. EPA extended new emissions reporting requirements for the petroleum and natural gas industries for smaller natural gas and petroleum production and distribution facilities. The final rule requires facilities that emit 25,000 metric tons or more of carbon dioxide equivalent (CO_{2E}) per year to report annual methane (CH_4)and CO_2 emissions from equipment leaks and venting. In addition, facilities will need to report emissions of CO_2, CH_4, and nitrous oxide (N_2O) from natural gas flaring and combustion at any stationary or portable onshore natural gas production or distribution source. This new rule went into effect on January 1, 2011, with first annual reports covering calendar 2011 emissions due to the U.S. EPA March 31, 2012.

Larger natural gas production and distribution facilities were already required to report CO_2, CH_4, and N_2O emissions. The extension obligates thousands of smaller natural gas facilities to report emissions to the U.S. EPA. The data collected as part of this new emissions reporting requirement may be used by U.S. EPA in potentially extending emissions reduction requirements to these smaller facilities. The new rule places an emphasis on methane gas, which was identified as a valuable fuel but a potent GHG. Activities that require reporting include onshore petroleum and natural gas production, offshore petroleum and natural gas production, onshore natural gas processing, natural gas transmission, underground natural gas storage, LNG storage, LNG import and export, and natural gas distribution.

This new rule appears to reflect findings in a technical support document released by the U.S. EPA on November 8, 2010, that doubles the previous estimates for the amount of methane gas that leaks from loose pipe fittings and is vented from natural gas wells. Previous estimates were based on emissions from the tailpipes or smokestacks and did not account for methane and other emissions that occur during the extraction, treatment, and delivery of natural gas. It is not yet clear what impact these reporting requirements and potential emissions reduction requirements may have on natural gas infrastructure.

On July 28, 2011, the U.S. EPA released for comment rules to reduce volatile organic compounds, methane, and chemicals known as "air toxics" emitted during production and transportation processes by the oil and natural gas industry.[161] The rules, which will be contained in the New Source Performance Standards (NSPS) and the National Emissions Standards for Hazardous Air Pollutants (NESHAP), includes air standards for wells that are hydraulically fractured, as well as emissions from pipelines, compressors, liquid storage tanks, and processing facilities.[162] The U.S. EPA emphasizes that it believes the new standards are cost-effective, in that revenues from selling the additional methane that is captured will cover the cost of compliance in less than one year

The proposed rules reduce Volatile Organic Compounds (VOCs) and air toxics (which include the hydrocarbons benzene, ethylbenzene, and n-hexane) emitted by:

- Wells: Via use of "green completion" techniques that separate natural gas and the liquid hydrocarbons from the flowback that comes from the well as it is being completed. The U.S. EPA estimates that 500,000 tons of VOCs are emitted each year, and the new rule will capture 95 percent of those emitted at fractured wells.[163] The process that captures the VOCs will coincidentally capture methane, reducing the amount of methane that would otherwise be vented by 26 percent, and the air toxics that would be vented by 30

161 The rules in Docket EPA-HQ-OAR-2010-0505 were not published in the Federal Register until August 23, 2011. They can be found at Federal Register, Vol. 76, No. 163, pp. 52738 -52843.

162 The NSPS formally appear in 40 CFR part 60 and the NESHAP in 40 CFR part 63.

163 U.S. EPA, *Proposed Amendments to Air Regulations for the Oil and Natural Gas Industry Fact Sheet*, p. 3. At www.epa.gov/airquality/oilandgas/pdfs/20110728factsheet.pdf, last accessed March 15, 2012.

percent.[164] Recompleting a well is considered a modification, subjecting existing wells that are recompleted to these new standards.[165]

- Compressors: Centrifugal compressors would require dry seal systems, and reciprocating compressors would have to replace rod packing systems every 26,000 hours of operation.
- Pneumatic controllers: New controllers (except when used to safely maintain line pressures) must not use gas to operate; existing controllers may not emit more than 6 cubic feet of gas per hour.[166]
- Condensate and crude oil storage tanks (except those smaller than 1 barrel per day of condensate or 20 barrels per day of crude) — must reduce VOC emissions by 95 percent. They would also have to reduce their air toxics by 95 percent, and the emissions from the tanks will become a factor in determining whether a facility is a major source.
- Natural gas processing plants — strengthen the existing NSPS to impose more leak detection and repair requirements and to reduce sulfur dioxide (SO_2) emissions.
- Dehydrators — the 1-ton-per-year benzene allowance would be eliminated, such that large dehydrators would have to reduce air toxics (of which benzene is one) emitted by 95 percent and limits would be created for dehydrators with throughput as low as 3 MMcfd. Exemptions contained in the old rule for failure during startup, shutdown, and maintenance would be eliminated.

On April 18, 2012, the U.S. EPA established the final rules and set January 1, 2015, as the deadline for full compliance. New rules for compressors and pneumatic controllers in the transmission (pipeline) segment of the industry that were part of the proposed rules have been eliminated from the final rules. However, compressors and pneumatic controllers on production facilities are still covered. New storage tanks at compressor stations with VOC emissions of 6 tons a year or more must reduce VOC emissions by at least 95 percent.

It is not yet clear which California facilities might be affected, but at least some of the state's facilities are expected to be among the 3,000 that the U.S. EPA estimates will need to comply. How these rules will be handled by the regional air quality management districts is unclear at this point. Some of California's natural gas facilities will also be covered under cap and trade regulations which are scheduled to go into effect in 2015, in response to Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006) (AB 32).

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164 Op. cit., p. 2.

165 The rule also requires a 30-day advance notification for each completion or recompletion of a hydraulically fractured gas well.

166 Controllers regulate pressure, flow, and temperature.

U.S.EPA PCB Regulations for Natural Gas Infrastructure

The U.S. EPA is reconsidering revisions to the use authorizations for polychlorinated biphenyls (PCBs) through an Advanced Notice of Proposed Rulemaking (ANPR).[167] PCBs are found in a variety of electrical equipment and in some natural gas pipelines. The U.S. EPA estimates a proposed rule could be published in April 2013.[168] The manufacture, processing, distribution, and use of PCBs were prohibited beginning January 1, 1977, under the Toxic Substances Control Act, which allows the U.S. EPA to issue rules authorizing certain uses of PCBs where they do not present an unreasonable risk of injury to health or the environment.[169] The agency is concerned that equipment containing PCBs, including electrical capacitors, transformers, heat transfer systems, and electric motors, permitted under current use authorizations, is at least 30 years old and much of it is nearing the end of its useful life.

PCBs are also found in some natural gas pipelines, where they were used as a lubricant in centrifugal compressors. PCBs at concentrations greater than 50 parts per million (ppm) in natural gas pipelines were prohibited effective May 1, 1980. However, in 1981, the U.S. EPA entered into agreements with 13 natural gas transmission companies with facilities that had been found to have concentrations greater than 50 ppm.[170] The agreements provided that the U.S. EPA would not bring enforcement actions against the pipelines for the improper use of PCBs, as long as they participated in the Compliance Monitoring Program (CMP) and undertook measures to reduce PCBs in their pipeline systems. The CMP was subsequently rolled into a set of revised use authorizations in 1998, permitting the use of PCBs in natural gas pipelines at concentrations greater than 50 ppm under certain conditions. The U.S. EPA originally believed that those use authorizations, still in place today, should have resulted in removal of PCBs to levels less than 50 ppm. However, the U.S. EPA says it has information that such reductions have not occurred, despite 30 years of operations and "after all known sources of PCBs were removed from these systems."[171]

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167 The ANPR appeared in the *Federal Register* on April 7, 2010. A pdf copy of the *Federal Register* notice can be found at http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OPPT-2009-0757-0001, or at: http://www.epa.gov/epawaste/hazard/tsd/pcbs/pubs/anpr6-16-10.pdf.

168 The "live" status Web page containing status and details for the PCB use authorization reassessment can be found at http://yosemite.epa.gov/opei/rulegate.nsf/byRIN/2070-AJ38. The docket number is EPA-HQ-OPPT-2009-0757.

169 Current rules can be found at 40 Code of Federal Regulations (CFR) 761. Section 6(e)(2)(B) of the Toxic Substances Control Act.

170 One of the 13 pipelines covered under the 1981 settlement was Transwestern, which serves California.

171 The ANPR appeared in the *Federal Register* on April 7, 2010, p. 17657.

The changes that the U.S. EPA is considering for natural gas transmission and distribution systems would require sampling to determine the extent of PCB contamination when any person finds PCBs in any system at concentrations greater or equal to 1 ppm. Sampling results greater than 50 ppm would be reported to the U.S. EPA. They suggest that an alternative revision may be to terminate use authorizations for levels above 1 ppm in a phase-out approach. Under this approach, pipeline owners would have to confirm the absence of those PCBs by 2020 phase-out date (through demonstration or through implementation of engineering controls) in areas where PCBs had previously been found.[172] If the U.S. EPA adopts the "survey and remediate" option instead of the full 2020 phase-out option, it has not yet been determined how long a period a pipeline would have to be remediated should concentrations above 50 ppm be found. However, the U.S. EPA has stated that it believes that the 10-year period since the prior revisions should have been sufficient time for removal of PCBs from compressed air systems, other natural gas, or liquid transmission systems; they are considering eliminating the use authorizations for these systems altogether.

The Interstate Natural Gas Association of America (INGAA) filed initial comments on the ANPR on PCB rules, followed up by a series of white papers.[173] INGAA has assumed the lead role in developing the pipeline companies' response in the proposed rulemaking process. Their comments emphasize that "natural gas pipelines are built and maintained for perpetual operation subject to rigorous inspection, operations and maintenance requirements established and enforced by" the U. S. Department of Transportation's Pipeline and Hazardous Material Safety Administration, including pipeline integrity management regulations. INGAA essentially argues that a tighter standard is not necessary to protect human health or the environment; that the U.S. EPA found as such when it replaced the CMP in the 1998 revisions; and that the cost to comply with the revised rule would be significant and, in some parts of the country, "devastating." INGAA estimates the cost of compliance, assuming 50 percent of the pipelines needed to be replaced, would range from $33 billion to $145 billion. INGAA also argues that, short of component replacement, purging the pipelines of PCBs is "technically impossible."[174] Notably, the pipelines whose

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172 This would be similar to what is required now under 40 CFR 761.30(i)(1)(iii)(A)(4).

173 INGAA's August 20 comments can be found at http://www.ingaa.org/cms/30/10729.aspx. INGAA's white papers can be found at http://www.ingaa.org/?ID=10724.

174 INGAA's white papers can be found at http://www.ingaa.org/?ID=10724. One of the INGAA-sponsored papers describes what it would actually take to remove PCBs from the pipelines. It describes how the PCBs are soluble in pipeline liquids (condensates). Solvent flushing or surfactant washing will not work and would introduce other undesirable chemicals. Pipeline liquids can wash the PCBs off the sides and pigs can push the liquids and debris through the pipe, which should result in gradual elimination of the PCBs for pipelines that can be pigged.

compressors most likely used PCBs and that would have higher concentrations stuck to walls or absorbed by o-rings, internal sealants, gaskets, greases, and so forth, are those built before PCBs were banned in 1979.

Several utilities, pipeline companies, and energy companies also submitted comments that expressed opposition.[175] Some of the comments submitted suggests that the mandatory phaseout of PCB-containing equipment is impractical, unnecessary, and counterproductive, and would place an undue burden on regulated communities and regulators alike.

The natural gas pipeline aspect of the ANPR is a small part of the overall changes the U.S. EPA proposes. It also asked for comments about capacitors and transformers in the electric system, including an inventory of equipment and the age thereof, and information about cost of immediate versus phased replacement. The U.S. EPA proposes to eliminate all use of oil-filled equipment showing concentrations of greater than 50 ppm by 2020 and to eliminate all use of any PCB-contaminated equipment with concentrations greater than 50 ppm by 2025. It also noted that the rigor of analysis required to support adoption of a use authorization is much higher than the rigor required to eliminate one.

The compliance costs associated with the proposed PCB rules are unclear at this time. If past experience is a guide, it seems likely that the final rule will be narrowed from that in the ANPR. If INGAA is correct, compliance costs could be large and, all else being equal, would likely result in higher natural gas pipeline transportation rates across the country. To the extent compliance affects some pipelines and not others, some impact can be expected on the basis differential prices or in the rebalancing of flows from producing basin to market.

175 See http://www.regulations.gov/#!docketDetail;dct=PS%252BPS;rpp=250;po=0;D=EPA-HQ-OPPT-2009-0757.

List of Acronyms

Acronym	Proper Name
AB 118	Assembly Bill 118
ANPR	Advanced Notice of Proposed Rulemaking
API	American Petroleum Institute
AOGC	Arkansas Oil and Gas Commission
API	American Petroleum Institute
APPA	American Public Power Association
Bbl	Barrel
Bcf/Bcf/d	Billion cubic feet, billion cubic feet per day
BTEX	Benzene, tolulene, ethylbenzene, and xylenes
Btu	British thermal units
CFR	Code of Federal Regulations
CFTC	Commodities Futures Trading Commission
CH_4	Methane
CME	Chicago Mercantile Exchange
CMP	Compliance Monitoring Program
CNG	Compressed natural gas
COMEX	Commodity Exchange
CO_2	Carbon dioxide
CO_{2E}	Carbon dioxide equivalent
CPUC	California Public Utilities Commission
DG	Distributed generation
Dth	Decatherms
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
EAP	*Energy Action Plan*
Energy Commission	California Energy Commission
EPNG	El Paso Natural Gas
ERCOT	Electric Reliability Council of Texas
F&D	Finding and development cost
FERC	Federal Energy Regulatory Commission
FTA	Free Trade Agreement
GDP	Gross Domestic Product
GHG	Greenhouse gas
GSP	Gross State Product
GWP	Global warming potential
Fracking	Hydraulic fracturing
GW/GWh	Gigawatt/gigawatt-hours
ICE	IntercontinentalExchange
INGAA	Interstate Natural Gas Association of America
Lamont-Doherty	Columbia University's Lamont-Doherty Earth Observatory

Acronym	Proper Name
LCFS	Low Carbon Fuels Standard
LNG	Liquefied natural gas
Lower 48	Lower 48 United States
MBtu/MMBtu	Thousands of British Thermal Units/Millions of British Thermal Units
Mcf	Thousands of cubic feet
Mcfe	Thousands of cubic feet equivalent
MISO	Midwest Independent System Operator
MIT	Massachusetts Institute of Technology
MMcf/MMcf/d	Million cubic feet/million cubic feet per day
MW	Megawatt
NAESB	North American Energy Standards Board
NARUC	National Association of Regulatory Utility Commissioners
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NGL	Natural gas liquids
NGSA	Natural Gas Supply Association
NSPS	New Source Performance Standards
NYMEX	New York Mercantile Exchange
N_2O	Nitrous oxide
OGS	Oklahoma Geological Survey
OMG	White House Office of Management and Budget
ONDR	Ohio Department of Natural Resources
PCBs	Polychlorinated biphenyls
PG&E	Pacific Gas and Electric Company
PNUCC	Pacific Northwest Utilities Conference Committee
PPM	Parts per million
PSEPs	Pipeline Safety Enhancement Plans
QFER	Quarterly Fuels And Energy Report
REX	Rocky Mountain Express
RFO	Residual fuel oil
RFS2	Renewable Fuels Standard
SCAQMD	South Coast Air Quality Management District
SDG&E	San Diego Gas & Electric
SEC	Securities and Exchange Commission
SoCal Gas	Southern California Gas Company
SO_2	Sulfur dioxide
Tcf/Tcf/yr	Trillion cubic feet/trillion cubic feet per year
TSD	Technical Support Document
U.S. EPA	United States Environmental Protection Agency
Th	Therms
USD	United States dollar
U.S. DOE	United States Department of Energy

Acronym	Proper Name
U.S. EIA	United States Energy Information Administration
USGS	United States Geological Survey
VOC	Volatile organic compounds
WSGR	Worldwide shale gas resources

APPENDIX A: Glossary of Terms

Adsorbed Gas: Methane molecules attached to organic material contained within solid matter.

Backbone Transmission System: The system used to transport natural gas from a utility's interconnection with interstate pipelines, other local distribution companies, and the California natural gas fields to a utility's local transmission and distribution system.

Border Price: This is a price at the border of a state; it represents the place where natural gas goes from an interstate pipeline to an intrastate pipeline. The border location is not always exactly on the border of a state, but is normally very close to it.

Carbon Footprint: The total set of GHG emissions caused directly and indirectly by an individual, organization, event, or product.

Casing: Pipe set with cement in the hole in the earth.

Combined Cycle Gas Turbine: An assembly of engines that converts heat into mechanical energy, which in turn drives electrical generators. The principle is that the exhaust of one heat engine is used as the heat source for another, increasing the system's overall efficiency.

Citygate Price: The price paid by a natural gas utility when it receives natural gas from a transmission pipeline. "Citygate" is used because the transmission pipeline often connects to the distribution system that supplies a city.

Coal-Bed Methane (CBM): Natural gas extracted from coal deposits.

Drilling: The process of boring a hole in the earth to find and remove subsurface fluids, such as oil and natural gas.

Environmental Impact: Adverse effect upon natural ambient conditions.

Formation: A bed or rock deposit composed, in whole, of substantially the same kind of rock; also called *reservoir* or *pool*.

Futures Market (natural gas): A trade center for quoting natural gas prices on contracts for the delivery of a specified quantity of a natural gas, at a specified time and place in the future. Natural gas futures start from the next calendar month and can go up through 36 months into the future. For example, on October 2, 1998, trading occurs in all months from November 1998 through October 2001.

Groundwater: Water in the earth's subsurface used for human activities, including drinking.

Henry Hub: Located in Southern Louisiana, is a key natural gas pricing point in the Lower 48.

Horizontal Well: A hole at first drilled vertically and then horizontally for a significant distance (500 feet or more).

Hydraulic Fracturing: The forcing into a formation of a proppant-laden liquid under high pressure to crack open the formation, thus creating passages for oil and natural gas to flow through and into the wellbore. Also known as "fracking" or "fraking."

Local Transmission System: The term *local transmission system* includes the pipeline used to accept natural gas from the *backbone transmission system*, and to transport it to the *distribution system*.

Manipulation: Any planned operation, transaction, or practice that causes or maintains an "artificial price." The Commodities Futures Trade Commission (CFTC) defines artificial price as a price higher or lower than it would have been if it reflected the forces of supply and demand.

Net Present Value: The process of finding the current-date value of a stream of cash-flows occurring in multiperiods. Present value of revenues minus present value of costs gives the net present value.

New York Mercantile Exchange (NYMEX): The world's largest physical commodity futures exchange. Trading is conducted through two divisions: the NYMEX Division, which is home to the energy, platinum, and palladium markets, and the COMEX Division, where metals like gold, silver, and copper and the FTSE 100 index options are traded. The NYMEX uses an outcry trading system during the day and an electronic trading system after hours.

Original Natural Gas-in-Place: The total initial volume (both recoverable and non-recoverable) of oil and/or natural gas in-place in a rock formation.

Permeability: The ability of a fluid (such as oil or natural gas) to flow within the interconnected pore network of a porous medium (such as a rock formation).

Porosity: The condition of a rock formation by which it contains many pores that can store hydrocarbons.

Production Decline Profile: A chart demonstrating the depletion of a producing well.

Proppant: A granular substance (sand grains, walnut shells, or other material) carried in suspension by a fracturing fluid that keep the cracks in the shale formation open after the well operator retrieves the fracturing fluid.

Recoverable Reserves: The unproduced but recoverable oil and/or natural gas in-place in a formation.

Rig Count: The number of drilling rigs actively punching holes in the earth.

Shale Gas: Natural gas produced from shale formations.

Shale: A fine-grained sedimentary rock whose original constituents were clay minerals or mud.

Spot Market (natural gas): A market in which natural gas is bought and sold for immediate or very near-term delivery, usually for a period of 30 days or less. The transaction does not imply a continuing agreement between the buyers. A spot market is more likely to develop at a location with numerous pipeline interconnects, thus allowing for a large number of buyers and sellers. The Henry Hub in Southern Louisiana is the best known spot market for natural gas.

Spot Price (natural gas): The price for a one-time open market transaction for near-term delivery for a specific quantity of natural gas at a specific location, where the natural gas is purchased at current market rates.

Stimulation: The process of using methods and practices to make a well more productive.

Tight Gas: Natural gas from very low-permeability rock formations.

Unconventional Production: Natural gas from tight formations or from coal deposits or from shale formations.

Well Completion: The activities and methods necessary to prepare a well for the production of oil and natural gas.

Well: A hole in the earth caused by the process of drilling.

Wellbore: The hole made by drilling. It may be cased, for example, by pipe set by cement within the hole.

Wellhead Price: The value at the mouth of the natural gas well. In general, the wellhead price is considered to be the sales price obtainable from a third party in an arm's length transaction (no transportation or processing costs are included). Posted prices, requested prices, or prices as defined by lease agreements, contracts, or tax regulations should be used where applicable.

APPENDIX B: Natural Gas Market Pricing Selected Topics

Natural Gas and Crude Oil Price Relationship

Many researchers find a long-run relationship between crude oil and natural gas prices. This relationship is an indirect one through fuel switching, and the data in the research stretch from 1990 through 2006.[176] RFO price is directly related to the price of crude oil, as RFO comes from crude oil in the refining process.

There are some basic reasons for the oil/natural gas price relationship. First, both resources have very similar geological characteristics, use the same drilling technology, and in some cases both oil and natural gas are produced together. Sometimes natural gas is used as an input fuel for enhanced oil recovery operations.[177] There are other factors that influence short-run price fluctuations that can go against the long-run relationship. Weather can affect natural gas prices through the number of heating and cooling degree days. Extreme cold/hot weather will increase the demand for space heating/air conditioning, which, in turn, will increase natural gas price. Natural gas storage inventories will also affect natural gas prices. A high level of storage at the beginning of the month implies natural gas supplies are plentiful, and thus, prices are expected to be lower than otherwise. Hurricanes and other seasonal factors have a strong influence on the short-run dynamic adjustment of natural gas prices.

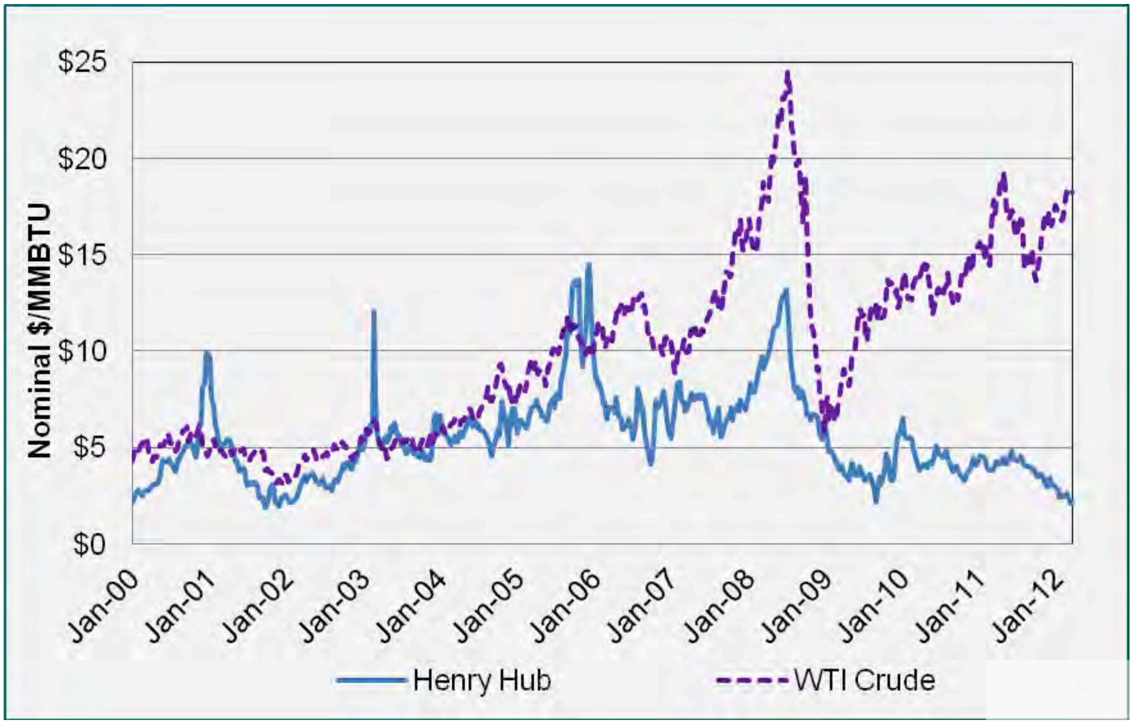
The relationship between crude oil and natural gas in the United States has seemingly weakened greatly since early 2009, as indicated by **Figure B-1.** This could, however, be a short-run deviation from the historical long-run trend relationship. One potential explanation for the oil/natural gas price relationship significantly weakening is the changing market structure of natural gas in the United States. Although natural gas, in the form of LNG, is often indexed against oil prices in world markets, the significant reduction of LNG imports has caused natural gas to become more of a regional market and less dependent on oil prices. The weekly data in **Figure B-1** shows that since the beginning of

176 RFO is used by manufacturers to produce heat and power. It is also used to heat homes and commercial buildings. Fuel switching normally occurs when the price of natural gas is more expensive than RFO, or when supplies of natural gas are low.

177 For more information on enhanced oil recovery operations, see http://www.energy.ca.gov/process/pubs/electrotech_opps_tr113836.pdf.

2012, the price spread between crude oil and natural gas is the largest it has been over the last 10 years.

Figure B-1: Natural Gas/Crude Oil Price Relationship



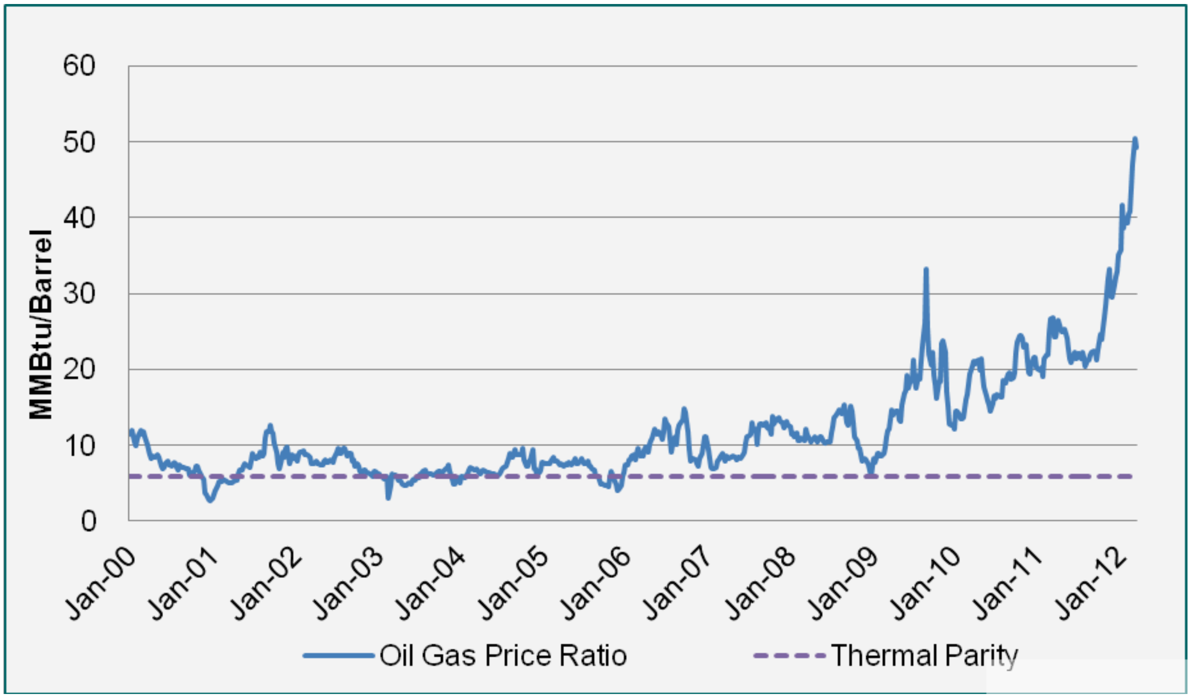
Source: www.eia.gov.

Crude Oil/Natural Gas Price Ratio (Oil/Natural Gas Ratio)

The oil/natural gas ratio is another measure of the relationship between crude oil and natural gas prices. The oil/natural gas ratio is composed of the price of Western Texas Intermediary crude oil, priced in $/barrel, divided by the Henry Hub natural gas prices, priced in $/MMBtu. The units of this ratio are in $/barrel divided by $/MMBtu, which reduces down to MMBtu/barrel. One barrel of Western Texas Intermediary crude oil has roughly 6 (5.825) MMBtus of heat content or energy in it. If a barrel of crude oil and a MMBtu of natural gas were priced strictly on the heat content of the fuel, staff would expect a barrel of crude oil to be roughly six times more expensive than a MMBtu of natural gas and have an oil/natural gas ratio of 6:1. When the oil/natural gas ratio is 6:1, the ratio is said to be at thermal parity. **Figure B-2** shows that the oil/natural gas ratio has sometimes been close to 6:1 ratio. However, since early 2009, when the relationship with crude oil and natural gas prices appeared to disappear, the ratio has been increasing. The oil/natural gas ratio averages 7.58:1 from 2000 through 2006, and 14.5:1 from 2007 through March 2011. From April 2011 through March 23, 2012, the oil/natural gas ratio averaged

28.6. The increase in the oil/natural gas ratio can be attributed to rising crude oil prices, and flat to declining natural gas prices. This increase is illustrated in **Figure B-2** by the steep slope of the oil/natural gas ratio over the last year.

Figure B-2: Oil/Natural Gas Price Ratio

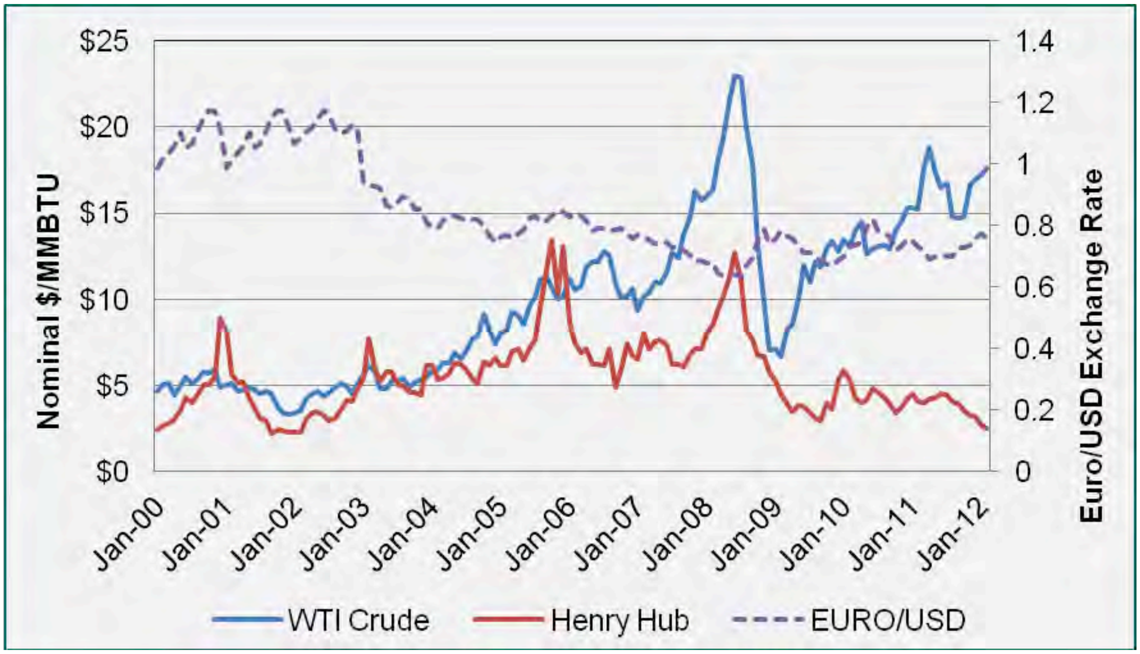


Source: U.S. EIA weekly crude oil and natural gas prices.

Natural Gas, Crude Oil, and Exchange Rates

Over the last decade, a close relationship between natural gas prices, crude oil prices, and the Euro/United States dollar (USD) exchange rate is noticeable. From the beginning of 2007 through mid-2008, the weakening of the USD relative to the Euro coincides with increased crude oil and natural gas prices (**Figure B-3)**. The data in this figure is monthly data, which goes through February 2012. During this period, the Federal Reserve repeatedly cut interest rates, which contributed to the weakening USD. The weakening USD and the prospect of more interest rate cuts may have scared investors out of currency and into commodities, causing the price of crude oil and natural gas to increase. As the USD strengthened value against the Euro in September 2008, the price of crude oil and natural gas started to decline.

Figure B-3: Natural Gas Price, Crude Oil Price, and Euro/USD Exchange Rates



Sources: www.eia.gov, and http://www.x-rates.com/d/EUR/USD/hist2010.html.

Researchers have examined the relationship between exchange rates and commodity prices (mostly crude oil prices). The research shows that exchange rates are a good indicator to forecast future commodity prices, but the converse is not true.[178] Exchange rates tend to be strongly forward-looking, while commodity price changes are usually more sensitive to short-term supply/demand imbalances.

Notice in **Figure B-3** that oil prices, over the last three years, generally rise/fall as the USD weakens/strengthens relative to the Euro; this relationship appears to fall apart at the end of 2009. This unraveling oil/exchange rate relationship could be a short-run deviation from a long-run trend, or the relationship could be evolving into a new long-run trend. Notice, also, that since the oil price/exchange rate relationship was unraveling, natural gas prices were hitting their low point and continued to hover around the $5 price level through the rest of 2010 and beginning of 2011. Since early 2011, natural gas prices have headed downward, towards the $2/MMBtu level, and crude oil prices have steadily increased for

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178 Y. Chen, K. Rogoff, & B. Rossi, *Can Exchange Rates Forecast Commodity Prices?* Harvard University of Economics, 2008. See http://www.economics.harvard.edu/files/faculty/51_Can_Exchange_Rates_Forecast_Commodity_Prices.pdf.

the most part. Over the last year, the Euro/USD exchange rate appears completely unrelated to both crude oil and natural gas.

Role of the Futures Commodity Market

The futures commodity market consists of both the wholesale physical and financial markets. Analysts argue that the futures market generally is competitive and produces accurate price signals for supply and demand, as well as long-term investment costs for production, transportation, and storage infrastructure. Financial markets can allow natural gas utilities to hedge their natural gas procurement costs to reduce the impact of volatile prices on customers.[179] Speculation without manipulation can improve market liquidity and absorb new information into prices.[180] If the futures market had no speculators, hedging with financial instruments could not exist. The analysts who view the futures market and speculators as beneficial believe regulating the futures market more closely would reduce the liquidity in which financial hedging instruments are traded.

At an August 5, 2009, CFTC hearing on position limits in financial markets, Elliot Chambers of Chesapeake Energy states:[181]

> Given such market volatility, and our highly active exploration and production program, we utilize responsible risk-management tools, such as once-through-cooling derivatives, to provide cash-flow certainty. Cash certainty is vital for planning and implementing our aggressive exploration and drilling program. Without the benefit of stability in cash flow, whether we drill one additional well or continue to develop an entire new potential natural gas field becomes a very problematic decision. Prudent risk management also allows us to invest in cutting-edge drilling and production technologies that help make our wells more economical and better for the environment. All of this is ultimately beneficial to American consumers and the United States economy as a whole.

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179 K. Costello, *Speculation in the Natural Gas Market: What it is and What It Isn't; When It's Good and When It's Bad*, National Regulatory Research Institute, 2008. See http://nrri.org/pubs/gas/speculation_gas_nov08-11.pdf.

180 Those trying to hedge against price volatility and shed risk can easily find a counter party (the speculator) to take on that risk when enough speculators exist in the market. The CFTC defines liquidity as "the ability to buy and sell futures contracts quickly without materially affecting the price."

181 Hearing on Speculative Position Limits in Energy Futures Markets, CFTC, August 5, 2009. See http://www.cftc.gov/PressRoom/Events/oeaevent080509.html.

Another researcher's opinion on speculation:

> Speculation in itself is not a bad thing. Good speculation provides a valuable market function. It helps local gas distribution companies and other large gas consumers, for example, to hedge against rising prices, and so to reduce risk—a significant benefit amid highly volatile gas prices and the current economic situation. By the same token, good speculation provides natural gas producers with more predictable future revenues, allowing them to expand with less uncertainty and lower borrowing costs. That trend, in turn, should help to lower the price of natural gas in the long run. Any attempt to curtail good speculation, therefore, is likely to make life harder for firms and raise natural gas prices.[182]

Other analysts and industry stakeholders have a slightly different view of speculation in the futures market. They assert the recent trend on more non-commercial traders entering the futures market has led to excessive speculation and price volatility.

Paul Cicio of the Industrial Energy Consumers of America stated at the CFTC hearing on speculative position:[183]

> Speculative limit exemptions are of concern and the more the CFTC lets financial speculative trading be less and less associated with the underlying commodity, the more it endangers price formation based on supply and demand. While the volume of natural gas consumed has remained almost unchanged over the last ten years, traded volume has increased multiple times along with volatility.

From the same CFTC hearing, Michael Greenberger, from the University of Maryland School of Law representing Americans for Financial Reform, states:

> If commercial interests cannot hedge in a fair and orderly market, they and their ultimate consumers, the public at large, are left to the mercy of extreme volatility that undercuts the hedging function. A contract market dominated by speculators changes the market from one that constructively shifts risk into a casino-like atmosphere consisting of bets on market direction unmoored from real world market responsibilities.

Figure B-4 shows one trading day on NYMEX for the Henry Hub Natural Gas Futures. Prices, in $/MMBtu, are on the right axis while the number of purchased contracts are on

182 K. Costello, *Speculation in the Natural Gas Market: What it is and What It Isn't; When It's Good and When It's Bad*. National Regulatory Research Institute, 2008. See http://nrri.org/pubs/gas/speculation_gas_nov08-11.pdf.

183 CFTC, *Hearing on Energy Position Limits in Energy Futures Markets*, August 5, 2009.

the left axis (one contract equals 10,000 MMBtu). The first thing to note from **Figure B-4** is the lack of long-term liquidity; after about 24 months trades become very scarce. Also, the natural gas price is steadily increasing with small uniform bumps in the winter months. Winters can be very cold or they can be mild, and price generally does not increase by the same amount every winter. Futures contracts, beyond the first six months, are settled by staff at NYMEX and market participants using relevant price spread relationships over different months.[184] This indicates that the futures contract price may not reflect the spot price in a given month.

Figure B-4: March 11, 2011, Trading Date for Henry Hub Natural Gas Futures Contract

Source: http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html.

184 See http://www.cmegroup.com/tools-information/lookups/advisories/market-regulation/SER-4867.html.

Regulation of Financial Commodity Markets

The Role of Price Speculation

There is significant debate on the effect of speculators on financial commodity markets and natural gas prices. A 2006 United States Senate report claimed that speculation contributes to oil-price volatility and recommended tighter controls on speculators.[185] On the other hand, some research finds that the influence of speculators on oil and natural gas price volatility is limited at best.[186] Other analysts find that speculative activity in the futures market does not have a significant impact on spot prices but has moderate influence on longer-dated futures.[187]

Manipulation of energy markets has occurred throughout recent history; fines, penalties, and even jail time have been the result for those guilty of market manipulation. Up through 2007, the Department of Justice has issued $430 million in monetary penalties against 25 companies, and criminal indictments against 42 individuals and companies.[188] El Paso Merchant Energy was convicted on charges related to false reporting of natural gas trading information and attempted market manipulation.

The Dodd Frank Act

The Dodd-Frank was signed into law on July 21, 2010. Portions of the Dodd-Frank Act apply to derivatives commonly used in energy markets. A lack of transparency about what transactions institutions have entered into and about the pricing of those transactions was deemed a contributing factor to the 2008 financial meltdown. In addition, claims of market manipulation and/or excessive speculation in commodity markets (including oil and natural gas markets) persist and have resulted in specific investigations and charges (for example, Amaranth Advisors, BP).[189]

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185 *The Role of Market Speculation in Rising Oil and Gas Prices: A Need to Put The Cop Back on The Beat—Staff Report*, Permanent Subcommittee on Investigations. Committee on Homeland Security and Governmental Affairs, U.S. Senate, June 27, 2006.

186 See R. J. Weiner, *Do Birds of a Feather Flock Together? Speculator Herding in the World Oil Market*, 2006. See http://www.rff.org/rff/Documents/RFF-DP-06-31.pdf.

187 See P. Berkmen, S. Ouliaris, and H. Samiei, *The Structure of the Oil Market and Causes of High Prices,* International Monetary Fund, 2005. See http://imf.org/external/np/pp/eng/2005/092105o.htm.

188 See http://www.cftc.gov/ucm/groups/public/@newsroom/documents/file/pr5405-07_factsheet.pdf.

189 A useful description of the Amaranth case and the issue of unregulated electronic exchanges such as the ICE can be found in the hearing report of the U.S. Senate's Permanent Subcommittee on Investigations, available at http://hsgac.senate.gov/public/_files/REPORTExcessiveSpeculationintheNaturalGasMarket.pdf.

The Dodd-Frank Act also imposes position limits on physical delivery contracts, such as Henry Hub natural gas. More specifically, it regulates swaps, or over-the-counter derivatives, that were not previously regulated. Generally, a swap exchanges a variable price stream for a known price stream or vice-versa. They are a standard tool used to mitigate the financial risk of changing values by transferring that risk to another party. In natural gas arrangements, we typically see swaps used to convert commodity prices at Henry Hub into a fixed price, to convert variable basis differentials into a fixed differential, or to convert a Henry Hub price into a price at a different market location such as SoCal Border or the PG&E Citygate.

The Dodd-Frank Act requires swap dealers and major swap participants to register.[190] There has been some debate about whether the CFTC will define swap dealers or deals to include the swaps that energy companies who are end-use generators sell to their end-use customers. The Dodd-Frank Act requires all swaps to be cleared by a third-party service, known as a "clearinghouse" or "exchange." These clearinghouses will impose collateral or margining requirements for capital to be posted to cover a portion of the value of the transaction, and will be used to cover losses should a party fail to perform as contracted. Every swap executed must be reported to the swap data repository authorized by the CFTC or Securities and Exchange Commission (SEC).[191] No repository is yet operational, and no dates for compliance have yet been established. The data to be reported include a full copy of the transaction confirmation slip, time of execution, price, the identity of the clearing organization, and any special conditions to the transaction.

Another element of the Dodd-Frank Act is to impose position limit (for example, caps on the number of contracts an entity may hold) on 28 contracts for physical delivery, including "economically equivalent" swaps so that no entity holds enough contracts to exercise market power by unilaterally moving market prices.[192] The 28 contracts include the NYMEX contracts for Henry Hub natural gas.[193] The position limit is 25 percent of deliverable supply for the relevant commodity in the spot month; outside the spot month

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190 Swap dealers are those that sell swaps or that enters into swaps for their own account.

191 There is an exemption that would allow commercial end-users who are not financial entities and who notify the CFTC how they will reduce counter-party credit risk associated with noncleared swaps to avoid using the clearinghouse. It appears that both publicly owned utilities and investor-owned utilities will qualify for the exemption.

192 *Economically equivalent* includes any contract in which price is set, referring to one of the explicitly covered contracts, or the delivery location has similar supply and demand characteristics as one of the covered contracts.

193 Three additional energy commodities are also covered including: Light Sweet Crude Oil, NY Harbor No. 2 Heating Oil, NY Harbor Gasoline Blend stock.

the limit is 10 percent of the open interest in a given contract, up to the first 25,000 contracts, and 2.5 percent thereafter. "Bona fide" hedging positions (for example, those entered into by end users) do not count toward the position limits. In other words, no single party can purchase contracts in any of the 28 commodities (including the four listed energy contracts, swaps, or economically equivalent contracts) for more than 10 percent of that contract's open interest.

Financial regulation laws, such as the Dodd-Frank Act, can affect natural gas prices by reducing the amount of speculation in the market. However, financial regulation in commodity markets may also scare investors away, as additional regulation may come with a cost, such as a tax on trades. This may cause the market to lose some of its liquidity and efficiency. For example, a trader, such as a natural gas price hedger, might be more reluctant to execute trades with additional costs, and their information will not be reflected in the price of the commodity. The price discovery function of the market (which is the outcome price of many buyers and sellers in the market) may be hurt as a result of the financial regulation of commodities.